Electricity Markets and Policy Group
Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

Impact of Wind, Solar, and Other Factors on Wholesale Power Prices

An Historical Analysis—2008 through 2017

Andrew D. Mills, Dev Millstein, Ryan Wiser, Joachim Seel, Juan Pablo Carvallo, Seongeun Jeong, Will Gorman

November 2019

This work was supported by the U.S. Department of Energy (DOE) under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The Transmission Permitting & Technical Assistance Division of the DOE's Office of Electricity provided primary funding support, supplemented with funding from the Office of Energy Efficiency and Renewable Energy's Wind Energy Technologies Office, Solar Energy Technologies Office, and Strategic Priorities and Impact Analysis Team.

Acknowledgements

This work was supported by the U.S. Department of Energy (DOE) under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The Transmission Permitting & Technical Assistance Division of DOE's Office of Electricity provided primary funding support, supplemented with funding from the Office of Energy Efficiency and Renewable Energy's Wind Energy Technologies Office, Solar Energy Technologies Office, and Strategic Priorities and Impact Analysis Team. We especially thank our many DOE sponsors for supporting this research: Rakesh Batra, Lawrence Mansueti, Matthew Rosenbaum, Patrick Gilman, Rich Tusing, Rebecca-Jones Albertus, Ammar Qusaibaty, Elaine Ulrich, Michele Boyd, Garrett Nilsen, Paul Donohoo-Vallett, Ookie Ma, and Steve Capanna. In addition, this research used the Lawrencium computational cluster resource provided by the IT Division at the Lawrence Berkeley National Laboratory (supported by the Director, Office of Science, Office of Basic Energy Sciences, of DOE under Contract No. DE-AC02-05CH11231).

We also appreciate early feedback provided by an esteemed group of external advisors on this work: David J. Maggio (ERCOT), Mark Rothleder (CAISO), Keith Collins (SPP), Ken Schuyer and Hung-po Chao (PJM), Becky Robinson and Jesse Hensley (FERC), Johannes Pfeifenberger (Brattle), Joseph Cavicchi (Compass Lexecon), Sue Tierney (Analysis Group), Bill Hogan (Harvard), Jim Bushnell (UC Davis), Ben Hobbs (Johns Hopkins), Lion Hirth (Hertie School), and Jesse Jenkins (MIT). Helpful early feedback was also provided by our DOE sponsors listed above, as well as by others at DOE, including but not limited to Nathaniel Horner, Cynthia Wilson, and William Booth. Jarett Zuboy provided substantial editing assistance.

Of course, any omissions or errors that remain are solely the responsibility of the authors.

Table of Contents

Table of Figures

Table of Tables

Acronyms and Abbreviations

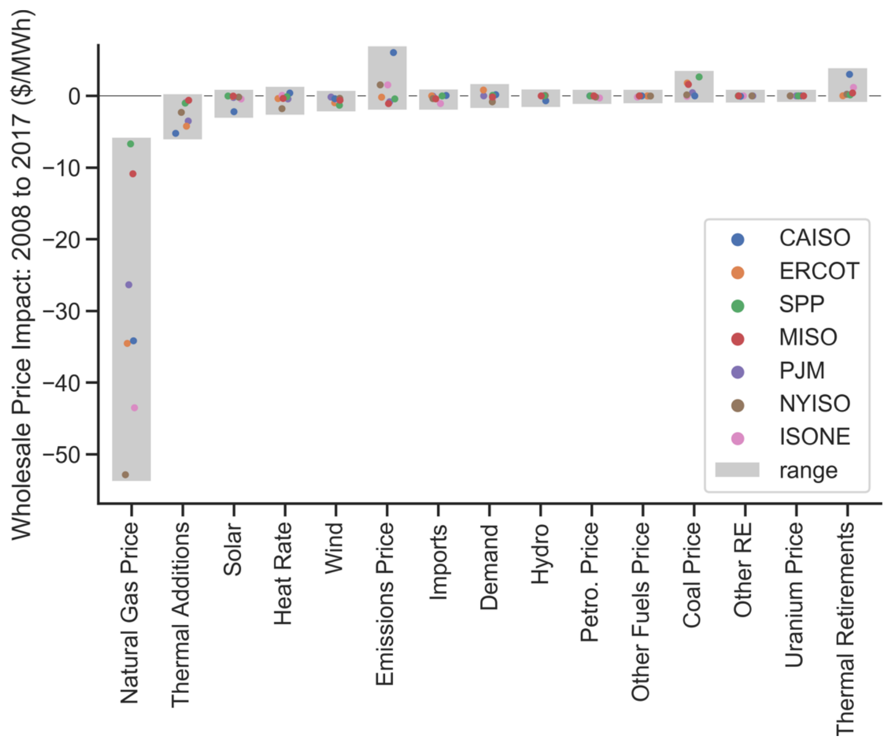
AEO	Annual Energy Outlook
AS	ancillary services
BNEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CEMS	continuous emission monitoring system
CO_2	carbon dioxide
CREZ	Competitive Renewable Energy Zone
DA	day-ahead
DPV	distributed photovoltaic
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
GTM	Greentech Media
ISO	independent system operator
ISO-NE	New England Independent System Operator
LMP	locational marginal price
MISO	Midcontinent Independent System Operator
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
NYISO	New York Independent System Operator
PJM	PJM Interconnection
PTC	production tax credit
RE	renewable energy
REC	renewable energy credit
RGGI	Regional Greenhouse Gas Initiative
RPS	renewables portfolio standards
RT	real-time
RTO	regional transmission organization
SAM	System Advisor Model
SEIA	Solar Energy Industries Association
SO_2	sulfur dioxide
SPP	Southwest Power Pool
TTS	Tracking The Sun
UPV	utility-scale photovoltaics
VRE	variable renewable energy

Executive Summary

Wholesale power markets in the United States have evolved over time. Some of the more notable changes over the last decade include growth in wind and solar, a steep reduction in the price of natural gas, limited growth in electrical load, and an increase in the retirement of thermal power plants. This report assesses the impact of these changes on wholesale electricity prices using two approaches. First, a supply curve model is used to quantify impacts to annual average wholesale prices at each centrally organized wholesale power market between 2008 and 2017. Second, hourly wholesale prices at all of the more than 60,000 pricing nodes are used to highlight the impacts of wind, solar, and other factors on trends in geographic and temporal pricing patterns.

In most markets, growth in wind and solar reduced average wholesale prices by less than $1.3/MWh. California is an exception, where growth in solar reduced prices by $2.2/MWh—perhaps foreshadowing greater impacts from solar in other regions as solar penetrations grow. Falling natural gas prices over this same period were the dominant driver of average market-wide wholesale prices, reducing average annual wholesale prices by $7–$53/MWh. The impact of wind and solar was secondary compared to the impact of natural gas, but among the biggest drivers in a second tier of factors with similar magnitudes, Figure ES-1. The second tier includes expansion and retirement of thermal generation, changes in demand, generator efficiency, coal prices, variations in hydropower, and emissions prices.

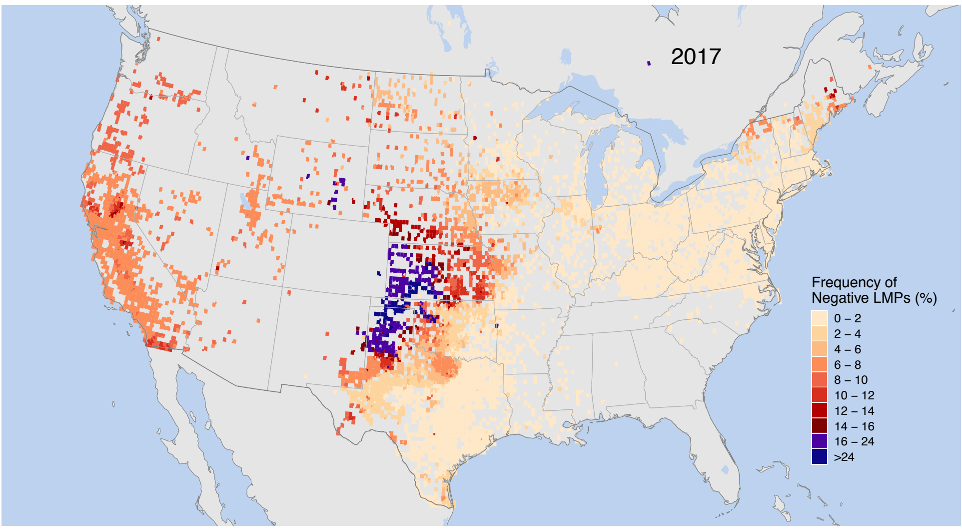
Figure ES-1. Average wholesale power energy price impact of various factors that changed between 2008 and 2017 across all ISO/RTO markets.



RE = renewable energy

Beyond the impacts to market-wide average annual wholesale prices, growth in wind and solar had a more consequential impact on prices in some locations and in altering how prices change based on the hour of the day and season. Specifically, growth in wind and solar impacted time-of-day and seasonal pricing patterns, growth in the frequency of negative prices was correlated geographically with deployment of wind and solar (Figure ES-2), and negative prices in high-wind and high-solar regions occurred most frequently in hours with high wind and solar output.

Figure ES-2. Frequency of negative real-time power prices in 2017.



LMP = locational marginal price

Despite the recent increase in frequency of negative prices, annual average prices at most locations have not been heavily impacted by these negative-price hours because negative prices were mostly small in magnitude. However, some regions have seen significant declines in annual average prices owing to negative hourly prices, specifically parts of the Midwest in the Southwest Power Pool, California, and northern areas of New York, New Hampshire, and Maine.

The regional clustering of negative prices means that not all generation has been equally impacted. In 2017, negative prices decreased the average annual real-time energy price at nodes near wind plants by about 6%, at nodes near solar plants by about 3%, and nodes near hydropower plants by about 3%. Pricing nodes near coal, gas, and nuclear plants saw a smaller reduction of about 1.5%, though those (modest) impacts have slightly increased over time.

Numerous factors beyond wind and solar influence local pricing patterns. Attempts to assess the impacts of wind and solar must carefully consider the full regional context.

1. Introduction

Wholesale power markets in the United States have evolved over time, reflecting changes in State and Federal policies, trends in the underlying resource mix and resource costs, and a desire to minimize system costs while meeting reliability standards. Some of the more notable recent changes impacting wholesale markets include growth in variable renewable energy (VRE, including wind and solar), a steep reduction in the price of natural gas, limited growth in electrical load, an increase in the retirement of thermal power plants, and efforts to slow the pace of retirements (DOE 2017).

This report assesses the degree to which growth in VRE has influenced wholesale power market prices in the United States—focusing on wholesale power *energy* prices, and principally on the 2008 to 2017 period. Wind and solar power capacity have both grown rapidly, motivated by declining costs (Wiser and Bolinger 2018; Bolinger and Seel 2018; Barbose and Darghouth 2018) as well as State and Federal policy.[1] The unique characteristics of these generation resources, meanwhile, also mean that they may have unique impacts on wholesale pricing patterns.

While the focus is VRE, where possible this report also assesses other drivers for the observed trends. The focus is also on national and regional system-level pricing trends and impacts in centrally organized wholesale markets, rather than impacts on specific power plants. The effects of State policies or particular market designs on price formation in wholesale electricity markets are out of the scope of this report, though both are currently topics attracting significant analysis and discussion for some regions.

The report first assesses the relative impact of VRE and other factors on annual, market-wide average historical wholesale power energy prices (wholesale prices),[2] from 2008[3] through 2017. The analysis includes all centrally organized wholesale markets in the United States, including the California Independent System Operator (CAISO), the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), the Midcontinent Independent System Operator (MISO), the PJM Interconnection (PJM), the New York Independent System Operator (NYISO), and the New England Independent System Operator (ISO-NE). Regions outside of those with independent system operators (ISOs)/regional transmission organizations (RTOs), i.e., those with bilateral-only markets, are excluded.

A consistent approach across regions results from applying a relatively simple, fundamental supply-curve model. The model disentangles the relative influence of wind and solar, changes in natural gas prices, plant retirements and additions, electricity load, emissions regulations, and other factors. The same tool is used to assess possible near-future annual average prices in the same regions, including an assessment of factors that may either increase or decrease those prices.

---

[1] See, for example: http://www.dsireusa.org/.

[2] As a convention, market-wide average historical wholesale power energy prices are referred to as average wholesale prices. In contrast, wholesale power energy prices at specific locations, which includes congestion, are referred to as locational marginal prices (LMPs).

[3] 2008 was chosen as the starting point as it saw the highest average wholesale prices across the United States.

Because the supply-curve modeling focuses only on average price impacts at the system level, the report then evaluates historical and recent trends in the temporal and geographic variability of wholesale prices, highlighting the impacts of VRE and other factors on pricing trends by location, time of day, and season as appropriate. Understanding how prices vary by location, time of day, and season is important, because these are the actual prices faced by generators and thus influence business decisions—whether to retire existing plants or build new plants, and how to operate and dispatch plants that are built. Specifically, the report evaluates hourly wholesale power energy pricing (locational marginal price, LMP) patterns at more than 60,000 pricing nodes across the United States, again focusing on ISO/RTO regions. The report explores geographic trends in annual average prices and trends in the overall distribution of prices, with special emphasis on the prevalence and causes of negative wholesale prices and some of the possible impacts of those prices. The report also evaluates a number of constrained pricing areas ("hot spots") to highlight the myriad drivers for pricing variations that occur based on location. The focus is on real-time (RT) prices (energy and congestion), but some treatment of day-ahead (DA) prices is included.

In both cases, the report builds on past literature (summarized in the next section), and refines and extends previous work by the same authors (Wiser et al. 2017)—increasing the geographic scope and resolution of the previous analysis; refining the methods, data, and factors considered; assessing impacts on DA (as well as RT) prices, estimating possible near-future impacts, and more.

This analysis is relevant to and may therefore inform a wide variety of contemporary discussions in the electric sector, at the State, regional, and Federal levels and among policymakers, regulators, system operators, utility planners, and supply- and demand-side resource investors:

- Geographic variations in prices can help illustrate the value of transmission expansion in order to reduce congestion, though any value so assessed ought to be balanced against the cost of new transmission infrastructure.
- Geographic price variability can also help inform power plant planning and siting decisions, because those prices signal locations where new generator additions might be more or less valuable.
- Temporal variations in wholesale prices, meanwhile, illustrate and—in part—dictate the value of flexible resources to the extent that flexible supply-side, demand-side, and storage resources can exploit and thereby help alleviate price variations.
- To the degree that price variations in general and negative wholesale prices in particular are affected by policy or institutional decisions, understanding the scope and prevalence of such impacts might inform policy reform decisions as well as ISO/RTO market design.
- Improved understanding of the drivers for wholesale price changes (and therefore revenue adequacy) may inform policy and market discussions related to the retirement of thermal plants to the extent that it may be easier to justify supporting at-risk generation if the drivers are policy related rather than simply decreased competitiveness relative to other resource options.
- Wholesale pricing trends and drivers may signal the value of or need for changes to wholesale power market design or participation to the extent that those pricing signals reflect an inability to

access the extant flexibility in the system.
- Finally, altered pricing patterns impact not only thermal plants, but also the market value of VRE, thereby affecting the economic competitiveness of VRE absent policy support.

A number of general points on the scope and limitations of the analysis deserve note.

- The focus is exclusively on the energy (and congestion) components of wholesale prices (LMPs) in regions with ISOs/RTOs. LMPs do not embed all the costs of operating the bulk power system, such as ancillary services, the cost of capacity (outside of the "energy-only" market design in ERCOT), or the full cost of transmission. The aggregate revenue of a generator participating in a wholesale market depends on the LMPs, ancillary service prices, capacity prices, and the dispatch of that generator. The focus on only LMPs therefore does not cover the full impact of wholesale prices on generator revenue.[4]
- While the results are relevant to the value and profitability of various supply-side, demand-side, transmission, and storage assets, those implications are not comprehensively assessed.
- Because the analysis does not address the cost of VRE or the cost of transmission, it also does not assess the full retail costs of electricity supply; instead, the emphasis is on the historical impacts of VRE on wholesale market prices.
- Many contracts between generators and loads exist outside of centrally organized wholesale spot markets. In this case, the LMP reflects the grid value of power and establishes the opportunity cost of not selling into or buying from the wholesale market, but it does not necessarily have a direct impact on the contracting parties. Similarly, some resources might participate in DA markets but then "self-schedule" in RT markets. In this case, the RT LMP establishes the opportunity cost for not participating in the RT market, but it does not have a direct impact on DA revenues. Ideally, market prices are not affected by the particulars of the contracting and hedging arrangements, because the system operator need not consider these arrangements in conducting the dispatch (Hogan 2016).
- The analysis seeks to decompose the core factors influencing wholesale prices, but wholesale markets are regionally varied and complex, so the simplified analysis is—by necessity—limited and incomplete.
- The focus is on areas of the country with centrally organized wholesale electricity markets (principally located within regions covered by ISOs/RTOs). Many of the issues addressed are also relevant—at least broadly—to regions with vertically integrated electric utilities and bilateral-only markets that operate outside of ISO/RTO regions.[5]

---

[4] In restructured markets, most generators receive the majority of their revenues through wholesale energy markets; see the various ISO/RTO market monitoring reports (e.g., Potomac Economics 2018a, 2018d, 2018b, 2018c; Monitoring Analytics 2018; SPP 2018a; CAISO 2018). Reserve markets deliver additional revenue to some generators, but generally in small quantities. In some regions, like the three eastern ISOs/RTOs with mandatory capacity markets (or requirements elsewhere that lead to bilateral capacity contracts) provide additional revenue to encourage resource adequacy, whereas in others (e.g., ERCOT) it is presumed that energy-market prices embed compensation for capacity during scarcity events.

[5] References to wholesale electricity prices in this report are most commonly associated with markets featuring an ISO/RTO, though less-liquid wholesale markets exist outside of ISO/RTO regions and, if so, are included in this analysis.

- By focusing on historical observed effects, the analysis may overstate the effects of VRE relative to what might occur in a long-run equilibrium. As VRE is added to an energy system, the long-run resource mix will gravitate towards a portfolio that accounts for the growing shares of VRE, which will tend to moderate the effects of VRE relative to what is observed in the near term prior to any adjustment in other resources. On the other hand, this is primarily (though not exclusively) an historical analysis of the period from 2008 to 2017, and the future impacts of VRE may become more pronounced should growth in VRE continue.

2. Background

2.1 The recent evolution of wholesale power markets

United States wholesale power pricing and bulk power system composition and operation have changed in recent years.[6] Average annual wholesale prices have declined substantially since 2008, while also experiencing sizable temporal and geographic variability. Oft-noted causes for these altered pricing patterns include the steep reduction in natural gas prices, the rise of VRE, and the moderation of load growth.

Regardless of the cause, a result of the reduced prices (among other factors) has been growth in thermal-plant retirements and a general decline in the capacity factors (and increased cycling) of coal power plants.[7] These changes have led to calls from some quarters to slow the pace of retirements through policy intervention and/or revisions to wholesale market design.[8] Separately, wholesale power markets have also evolved to better respond to the increased variability of VRE, in part by encouraging supply-side and demand-side flexibility, with discussions ongoing about further necessary adjustments.[9] Utility planners and regulators as well as private-market actors have similarly responded to the growth in VRE by planning for and investing in measures to enhance flexibility and respond to periods of over-generation. The marginal market value of VRE in wholesale markets, meanwhile, has declined over time, in part due to wind and solar suppressing prices during periods of high VRE output (Wiser and Bolinger 2018; Bolinger and Seel 2018).

2.2 Literature review of wholesale power price drivers

Wholesale power prices are affected by the presence of VRE and the incentives motivating VRE deployment, but also by a wide array of other factors, including the source mix, fuel prices, environmental regulations, other variable operating costs, electric system flexibility, electricity load patterns, transmission availability, market design, degree of integration with neighboring markets, and policy interventions. Given the myriad influencing factors, an open question is how and to what extent VRE deployment and the incentives motivating that deployment contribute to wholesale price patterns.

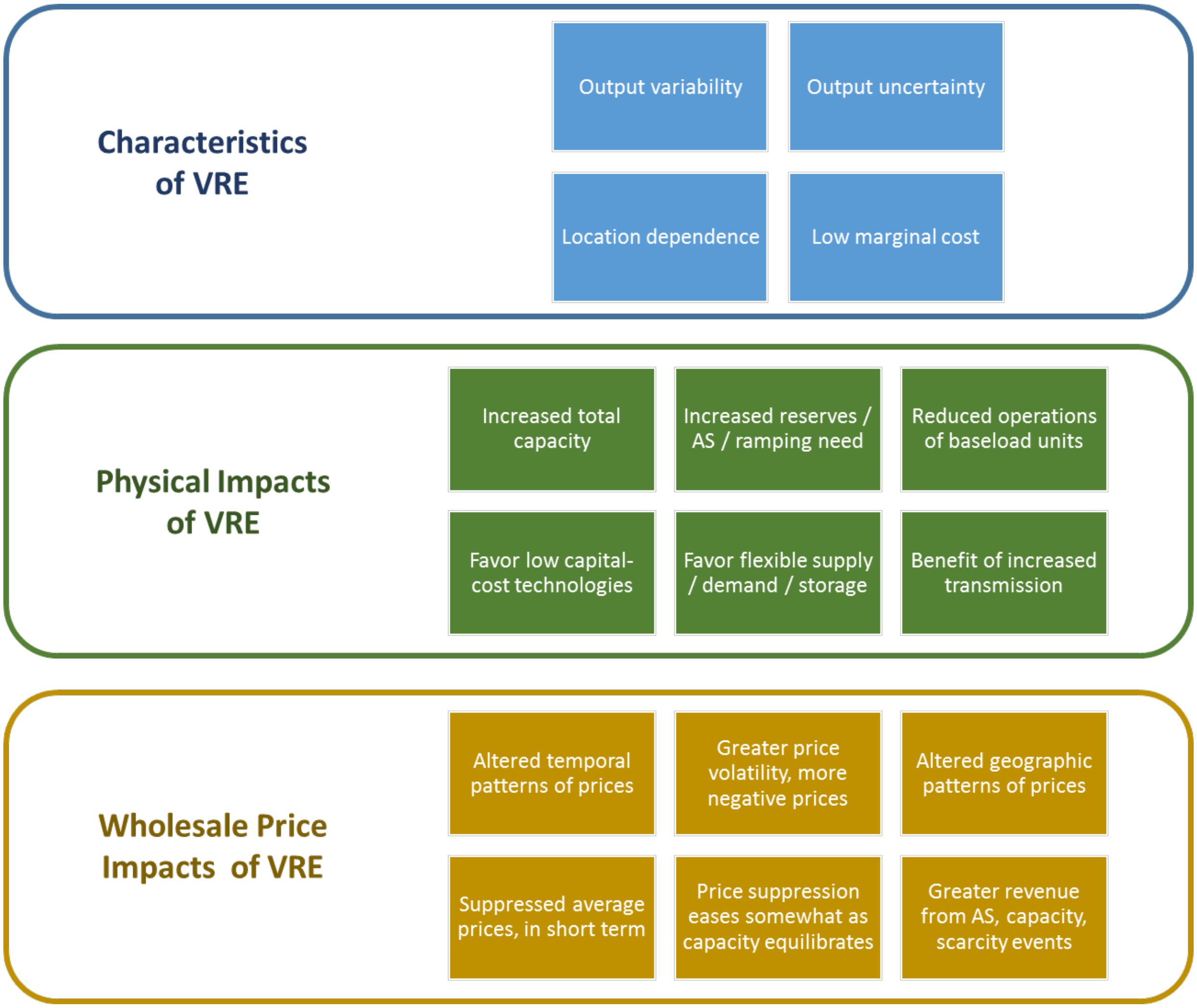
A large literature clarifies the unique characteristics of wind and solar resources, and investigates how those characteristics have affected or may in the future impact wholesale power prices (Wiser et al. 2017). Key characteristics of VRE and the associated physical and wholesale-pricing implications are

---

[6] These changes are summarized by DOE (2017, 2018); Wiser et al. (2017), Mills, Wiser, and Seel (2017); and Hibbard, Tierney, and Franklin (2017).
[7] See DOE (2017); Mills, Wiser, and Seel (2017); Hibbard, Tierney, and Franklin (2017); Linn and McCormack (2017); and EIA 2018a.
[8] Examples include Gifford and Larson (2017, 2016); Haratyk (2017); Balash et al. (2018); Makovich and Richards (2017); and Shawhan and Picciano(2019).
[9] Summaries of changes and ongoing discussions include Ela et al. (2017, 2016); Milligan et al. (2016); IEA (2016); Chang et al. (2017); Hogan and Pope (2017); Hogan (2010); Newberry et al. (2017); Orvis and Aggarwal (2017); Spees et al. (2018); Herrero, Rodilla, and Batlle (2018); Llobet and Padilla (2018); and Goggin et al. (2018).

summarized in Figure 1.

Figure 1. VRE characteristics and expected impacts on the bulk power system.



AS = ancillary services

Much of the literature supporting the wholesale price impacts summarized in Figure 1 is based on modeled scenarios with higher levels of VRE than are currently experienced.[10,11] Studies often show

[10] For a summary of the literature focused on the United States, see Wiser et al. (2017), or see individual studies (e.g., GE Energy 2005, 2010a, 2014; Fagan et al. 2012, 2013; NESCOE 2017; Brancucci Martinez-Anido, Brinkman, and Hodge 2016; LCG 2016; ISO-NE 2016; Tabors et al. 2015; Tabors, Rudkevich, and Hornby 2014; NY-ISO 2010; ABB 2014; NREL 2012; Deetjen et al. 2016; ISO-NE 2017a; Green and Léautier 2015; Hummon et al. 2013; Mills and Wiser 2012; EnerNex 2011; Levin and Botterud 2015; Seel, Mills, and Wiser 2018).

[11] Literature from Europe and Australia also includes empirical and modeled assessments (Sensfuß, Ragwitz, and Genoese 2008; Welisch, Ortner, and Resch 2016; Perez-Arriaga and Batlle 2012; Kyritsis, Andersson, and Serletis 2017; Brouwer et al. 2016; Würzburg, Labandeira, and Linares 2013; Cludius et al. 2014; Cutler et al. 2011; MacCormack et al. 2010; Ederer 2015; Haas et al. 2013; Clò, Cataldi, and Zoppoli 2015; Sáenz de Miera, del Río González, and Vizcaíno 2008; Green and Léautier 2015; Benhmad and Percebois 2018; Annan-Phan and Roques 2018).

greater impacts with higher levels of VRE. Impacts from modeled high VRE scenarios may therefore foreshadow impacts with continued VRE growth from current levels.

A consistent theme in the literature is that the degree and nature of any VRE-induced pricing impact are affected by the underlying physical and institutional flexibility of the electricity system (e.g., Cochran et al. 2014; Denholm et al. 2016; IEA 2011). Specifically, some of the physical and wholesale price impacts listed in Figure 1 will be less pronounced when the rest of the electricity system is flexible and thus better able to respond to shifts in demand and VRE availability (e.g., Chang et al. 2017). In part as a result, under "equilibrium" conditions (after retirement and new investment decisions are made accounting for VRE), the scale of any pricing impacts is expected to moderate, at least to some degree (Hirth 2013; Sáenz de Miera, del Río González, and Vizcaíno 2008).

2.2.1 Literature on impacts of VRE on annual average wholesale power prices

An increasing number of studies address the already-observed empirical impacts of growing VRE penetrations on wholesale power prices.[12] Some studies have used historical observations to estimate the impact of VRE on average wholesale power energy prices in different regions of the United States (Table 1). In restructured markets, wholesale energy prices (i.e., LMPs) are generally set by the generation offer cost of the marginal unit in a given period at a given location. Exceptions to this can occur, particularly in the presence of transmission congestion or when supply is insufficient to meet demand and prices are set based on demand bids or administratively set prices. The addition of VRE with low marginal costs shifts the supply curve out to the right, leading to lower market-clearing prices, all else being constant; the same would be true for any low-marginal-cost source. Incentives for VRE to bid into markets at negative prices may accentuate this effect, but only when those bids are on the margin.[13] This price reduction is often referred to as the "merit-order effect." The wholesale price reduction is sometimes touted as a benefit to consumers that purchase power in wholesale markets, but it represents an economic transfer from generators to consumers rather than a net social benefit (Felder 2011).

[12] Studies addressing already-observed impacts include wind and solar (e.g., Maggio 2012; Woo et al. 2011, 2013, 2014; Woo, Horowitz, et al. 2016; Woo, Moore, et al. 2016; Gil and Lin 2013; Wiser et al. 2016; Jenkins 2017; Hogan and Pope 2017; Makovich and Richards 2017; DOE 2017; Bajwa and Cavicchi 2017; DOE 2018; R. H. Wiser et al. 2017; Haratyk 2017; Craig et al. 2018; Bushnell and Novan 2018; Quint and Dahlke 2019; Tsai and Eryilmaz 2018).

[13] The PJM market monitor reports that 3%–7% of the marginal units in the RT market in PJM were wind between 2013 and 2017 (Monitoring Analytics 2018). MISO, meanwhile, has areas where local prices are frequently set by wind, even though wind never set the system-wide marginal price in 2017 (Potomac Economics 2018d).

Table 1. Average wholesale power energy price reduction associated with VRE growth.

Study	Applicable Region	Period	Average VRE Penetration (% of demand)	Decrease in Average Wholesale Power Energy Price from Average VRE
Woo et al. (2011)	ERCOT	2007-2010	Wind: 5.1%	Wind: $2.7/MWh (ERCOT North) Wind: $6.8/MWh (ERCOT West)
Woo et al. (2013)	Pacific NW (Mid-C)	2006-2012	N/A	Wind: $3.9/MWh
Woo et al. (2014)	CAISO (SP15)	2010-2012	Wind: 3.4% Solar: 0.6%	Wind: $8.9/MWh Solar: $1.2/MWh
Woo et al. (2016)	CAISO (SP15)	2012-2015	Wind: 4.3% Solar: 2.6%	Wind: $7.7/MWh Solar: $2.1/MWh
Gil and Lin (2013)	PJM	2010	Wind: 1.3%	Wind: $5.3/MWh
Wiser et al. (2016)[a]	Various regions	2013	RPS energy: 0%-16% depending on the region	RPS energy: $0 to $4.6/MWh depending on the region
Craig et al. (2018)	CAISO	2013-2015	Distributed solar: ~5%	Distributed solar: < $1/MWh
Tsai and Eryilmaz (2018)	ERCOT	2014-2016	Wind: 11%	Wind: $8 to $12/MWh
Quint and Dahlke (2019)	MISO	2014-2016	Wind: 6%	Wind: $6.7/MWh
Jenkins (2017)[b]	PJM	2008-2016	N/A	Wind: $1 to $2.5/MWh
Wiser et al. (2017)[b]	CAISO	2008-2016	Solar: ↑ 9.5% 2008-2016 Wind: ↑ 3.3% 2008-2016	Solar: $1.9/MWh Wind: $0.4/MWh
Wiser et al. (2017)[b]	ERCOT	2008-2016	Wind: ↑ 10.8% 2008-2016 Solar: ↑ 0.3% 2008-2016	Wind: $0.7/MWh Solar: $0/MWh
Haratyk (2017)[b]	Midwest	2008-2015	Wind: ↑ 9% 2008-2015	Wind: $4.6/MWh
Haratyk (2017)[b]	Mid-Atlantic	2008-2015	N/A	Wind: $0/MWh
Bushnell and Novan (2018)[b]	CAISO	2012-2016	Utility-scale solar: ↑ 8.3% 2012-2016	Solar: $5.2/MWh

Notes: a – Price effect is estimated impact of renewables portfolio standards (RPS) energy relative to price without RPS energy in 2013 before making adjustments due to the decay effect discussed by the authors. b – Decrease in average wholesale price is based on change in wind or solar energy from beginning to end of the period, rather than the decrease from average wind or solar reported in other rows.

Table 1 reports the historical effect of VRE on average annual wholesale power energy prices, based on the available literature. In some cases, the table reports results as a decrease in the average wholesale power energy price with the average amount of VRE over the study period, relative to the average price without the VRE; where available, the table includes the VRE penetration as the average VRE over the period relative to the average demand. In other cases, the table reports the impact of growth in VRE over a specified period on annual average wholesale prices. The estimated reduction in average wholesale prices from wind and solar ranges from $0–$12/MWh, depending on the region, the period of the analysis, the VRE technology and its level of penetration, and the study. A study focused on ERCOT finds higher merit-order effects in the wind-rich West Texas region, where transmission constraints led to reduced and negative prices before Competitive Renewable Energy Zone (CREZ) transmission assets were completed in 2013 (EIA 2014). Another study estimates the relative impact of different drivers for wholesale price reductions from 2008 through 2016, finding that the decline in natural gas prices was the dominant factor, resulting in wholesale price reductions of roughly $20/MWh; growth of wind was found to have a much smaller effect of about $1–$2.5/MWh (Jenkins

2017). This is consistent with the results shown in Wiser et al. (2017), which found that natural gas price reductions have been the dominant driver for low wholesale prices in ERCOT and CAISO over the last decade, with VRE growth playing a much smaller role. It is also consistent with the results in Haratyk (2017), which demonstrate that the declining price of natural gas was a larger influence on wholesale prices between 2008 and 2015 in both the Midwest and Mid-Atlantic than was growth in VRE.

Additional studies, sometimes using more stylized and/or partial assessments, are not included in Table 1. Makovich and Richards (2017), for example, find that wind in ERCOT reduced market-clearing prices by one third during the 2014 peak-demand period, but that "wind output wholesale price suppression around the average load segment is relatively modest because the supply curve is relatively flat." A quantitative assessment of the price-suppression impacts outside of the peak-demand period is not provided, and no annual average estimate is presented. Makovich and Richards (2017) also explore the impacts of wind in PJM in 2015, finding that wind output suppressed prices by 24% during the 15% of maximum net-load hours, 4% during the 15% of hours around average net load, and 9% during the minimum net-load hours. Hibbard, Tierney, and Franklin (2017) and Hogan and Pope (2017) present somewhat similar analyses, for PJM and ERCOT, respectively, but neither offers a clear assessment of historical impacts on annual average wholesale prices.

This sample of U.S.-focused studies is a subset of a much broader literature of similar analyses of the price effect of wind and solar in Europe, with many of the studies summarized by Welisch, Ortner, and Resch (2016) and Würzburg, Labandeira, and Linares (2013). Related work has sought to explore the relative influence of VRE and other factors on past wholesale prices in Europe (Kallabis, Pape, and Weber 2016; Hirth 2018; Bublitz, Keles, and Fichtner 2017). Overall, the merit-order effect estimates reported in Table 1 are within the range of results for wind and solar in European countries.

2.2.2 Literature on impacts of VRE on geographic and temporal variations in wholesale power prices

Wholesale electricity price volatility may also be expected to increase in systems with high VRE penetrations. Woo et al. (2011), for example, predict that a 10% increase in wind will increase the variance of wholesale prices by 1% in ERCOT North and 5% in the wind-rich ERCOT West. Levin and Botterud (2015) and Mills and Wiser (2012) similarly show that energy market price volatility generally increases with increasing VRE penetration. Other work, however, has found that growth in wind has had a particularly large price-suppression effect during peak periods, at least in ERCOT and PJM (Makovich and Richards 2017). Wiser et al. (2017), meanwhile, examine the volatility of RT prices at a small number of major pricing hubs across the United States, but they do not find any compelling trends over time related to increasing VRE penetrations. The market monitor for ERCOT, however, has suggested that higher price volatility in the spring and fall months of 2015 and 2016 was associated with higher wind volatility and load and wind forecast errors (Potomac Economics 2017a).

One clear signal for price volatility comes in the form of the frequency of negative wholesale energy prices. Negative prices typically arise from surplus supply along with technical or economic constraints that prevent reductions in generation output. Transmission limitations tend to be an accelerant of negative pricing, driving prices lower in congested markets as the surplus supply is unable to find other markets in which to sell.[14] Because negative pricing is a symptom of excess supply, the prevalence of negative pricing is greater during periods with lower system-wide load. Excess supply conditions can be exacerbated when potential sources of flexibility do not participate in markets. For example, load serving entities can choose to "self-supply" by using their own generation to meet their electrical demand, irrespective of market prices. Similarly, rigid contracts that do not allow for economic curtailment can exacerbate conditions. ISO-NE highlights several periods in which unpriced generation (resulting from fixed imports, self-scheduled generation, and generation up to economic minimum levels) was almost sufficient to meet periods of low demand, leading to very little generation being economically dispatched to meet demand and—as a result—bids with negative prices clearing the market (ISO-NE 2018). Up to a point, policy incentives (see Section 2.3) for renewable resources provide an incentive for renewable generators to continue to produce energy even when the energy price is negative. Even market demand for "green energy" yields positive prices for renewable energy credits (RECs), creating incentives for negative-price bids by VRE.

Of course, VRE resources are not the only resources that bid negative prices in wholesale markets. The lack of flexibility from existing U.S. nuclear power plants, for example, means that these plants will often self-schedule or bid negative prices to avoid costly shutdowns and startups. Some nuclear generation in PJM, for example, both self-schedules a certain amount of must-run generation and then bids a small fraction of the generation as dispatchable at negative prices (Monitoring Analytics 2018). Fossil units (coal or natural gas) may also contribute to negative prices, in part due to costs associated with startup and shutdown. In ERCOT, for example, the energy up to minimum generation levels is considered by the dispatch software to have a price of negative $250/MWh (Potomac Economics 2018a). Even hydropower plants sometimes generate during negative-priced hours, in some cases due to run-of-river operations and in others as a result of environmental and other flow constraints. Other units may have contractual requirements that create the same incentives for negative bidding, or they may be required to operate for reliability purposes regardless of market pricing and are therefore compensated through other contractual means.

Wiser et al. (2017) explore pricing at a limited number of major pricing hubs across the United States, finding that negative prices in most of these hubs continue to be rare, and almost nonexistent in DA prices. However, there is evidence of increased frequency of negative RT prices with increasing VRE. Further analysis of the time and geographic profiles of negative pricing events can help identify the many underlying causes. It can also inform the geographic scope of negative pricing events given that transmission limits between generation locations and load centers can lead to congestion and a higher prevalence of negative pricing in constrained zones and nodes. Wiser et al. (2017), for example, also focus on two "hot spots" for negative wholesale prices: West Texas and Northern Illinois. They show that high levels of VRE, nuclear, and hydropower—especially in concert with low load and transmission

[14] Section 4 further describes an example in ISO-NE where negative prices could occur at particular nodes owing to transmission congestion even prior to negative bids being allowed by generators. Once negative bids were allowed, negative prices became more frequent and widespread.

limits—can boost the frequency of negative pricing; new transmission investment, meanwhile, can lower the prevalence of negative prices. Hogan and Pope (2017) find that the profile of negative pricing in ERCOT correlates with wind production, and CAISO (2017b) shows that negative prices occurred during daytime hours in 2016—times of high solar generation—whereas most were during nighttime hours in 2012. Bajwa and Cavicchi (2017) review numerous hubs in many of the U.S. ISOs/RTOs, tracking negative pricing trends over time and diurnally, finding that the trends in negative-price hours suggest a VRE impact. DOE (2018) similarly reports the frequency of negative prices, as well as overall price distributions for the energy and congestion components of LMPs, across the United States. The effect of hydropower on negative prices in California and the Northwest is covered in Davis (2017).

Finally, the temporal patterns of wholesale energy prices may also change as a result of growth in VRE. This is evident in the many modeling studies cited earlier. It is also already observed in California, where strong solar output generally reduces prices during sunny midday periods (especially when runoff driving hydropower is also significant and load is low), but then causes prices to increase as the sun sets and other generation resources respond to the system's net-load ramp (Bushnell and Novan 2018).

2.3 Policy incentives and their influence on wholesale power prices

Some have noted that policy incentives for VRE can exacerbate pricing impacts. In particular, wind energy has historically received a 10-year Federal production tax credit (PTC). Additionally, both solar and wind benefit from renewables portfolio standards (RPS) in many states. RPS policies require load-serving entities to meet a specified share of their sales with energy produced by RPS-eligible generators. Depending on the state, load-serving entities achieve these targets through the purchase of RECs that put a value on energy generated by RPS-eligible resources above the wholesale price of power. Federal and State policies create incentives to deploy low-marginal-cost wind and solar resources, sometimes in the absence of any obvious physical energy-system need for additional generation or capacity. As described in Section 2.2, this deployment of additional generation can lead to lower wholesale power prices. Moreover, the PTC and State RPS programs create incentives for VRE plant owners and purchasers to bid that generation into wholesale markets at negative prices. The reason is simple: curtailment of generation will result in not only lost energy-based revenue, but also potentially lost incentive value (Hogan and Pope 2017; Levin and Botterud 2015). The investment tax credit (ITC), used for solar energy, does not create a similar incentive for bidding at negative prices.

2.4 Influence of wholesale price patterns on economic competitiveness of various investments

The altered wholesale price patterns that result from increased VRE will impact the relative profitability of different electric-sector assets. As detailed in Wiser et al. (2017) and summarized in Figure 1, the pricing impacts tend to favor flexible supply- and demand-side technologies, especially those with lower capital costs, and tend to disadvantage technologies with high capital costs and a lack of flexibility attributes. Temporal pricing volatility can also favor storage (Denholm, Eichman, and Margolis 2017; Denholm and Margolis 2016), whereas geographic patterns in prices can signal the value of new transmission infrastructure (Du and Rubin 2018; FERC 2017).

While most of the literature is based on modeled scenarios with higher levels of VRE penetration than are currently experienced,[15,16] some VRE influences are already apparent and/or are being discussed internationally and in some regions of the United States.[17]

VRE investments may be particularly impacted by the resulting wholesale price patterns, because VRE depresses prices in the very hours with high VRE generation. While VRE investors may be shielded from this “value decline” in the event that long-term fixed-price contracts exist, the decline in system value of VRE will, in that instance, affect the purchaser of VRE generation. Some of the literature has focused on historical trends in wind and solar value in the United States, Europe, and Australia based on observed wholesale price patterns and VRE output.[18] Other literature relies on modeled (and typically higher-VRE-penetration) scenarios.[19] A subset of the literature, meanwhile, has also explored how to boost (or slow the decline of) the system value of VRE with increasing penetration, through changes in renewable technologies and deployment as well as changes in broader system-level electric conditions such as new transmission, increased generation and load flexibility, and storage.[20]

---

[15] Studies based on models include (e.g., Traber and Kemfert 2011; Lamont 2008; Bushnell 2010; DOE 2012, 2015; NREL 2012; Mills and Wiser 2012, 2015, 2014; Steggals, Gross, and Heptonstall 2011; Di Cosmo and Malaguzzi Valeri 2014; De Jonghe et al. 2011; Chao 2011; Brouwer et al. 2016; Clò and D’Adamo 2015; Levin and Botterud 2015; Bloom et al. 2016; GE Energy 2010b; Agora 2015; Green and Léautier 2015; Bistline 2017).

[16] Most of these studies investigate the price effects of combined wind and solar penetrations up to 30% of a system's annual energy requirements, though some publications analyze shares up to 50% (Lamont 2008; NREL 2012; Brouwer et al. 2016; Bistline 2017) or even 75% (Agora 2015).

[17] Studies based on observed impacts include (e.g., Makovich and Richards 2017; Potomac Economics 2017a, 2017b; SPP 2017; CAISO 2017; FERC 2017; Bushnell and Novan 2018).

[18] Literature on the observed value includes (Hirth 2016; Clò, Cataldi, and Zoppoli 2015; Cutler et al. 2011; Welisch, Ortner, and Resch 2016; Gilmore et al. 2014; Bolinger and Seel 2018; Wiser and Bolinger 2018; Bushnell and Novan 2018).

[19] Literature on the modeled value includes (e.g., Mills and Wiser 2012, 2013, 2014; Hirth 2013; Hirth, Ueckerdt, and Edenhofer 2015; Lamont 2008; Bushnell 2010; Green and Léautier 2015; Sivaram and Kann 2016; Olson and Jones 2012; Levin and Botterud 2015; Bistline 2017; Birk and Tabors 2017; Agora 2015; MIT 2015; Reichenberg et al. 2018).

[20] Studies include (e.g., Mills and Wiser 2015; Hirth 2016; Denholm et al. 2016; Deetjen et al. 2016; Winkler et al. 2016; Hartner et al. 2015; Ederer 2015; Obersteiner 2012; Tveten, Kirkerud, and Bolkesjø 2016; Hirth and Müller 2016; Denholm and Margolis 2016; Denholm et al. 2015; Denholm, Clark, and O’Connell 2016; Birk and Tabors 2017; May 2017; Obersteiner and Saguan 2011; Riva, Hethey, and Vitina 2017; Denholm, Eichman, and Margolis 2017; Gilmore et al. 2014; Forsberg et al. 2017; Hale, Stoll, and Novacheck 2018; Johansson et al. 2017).

3. Impacts of VRE on Annual Average Wholesale Power Prices

3.1 Data and methods

To estimate the impact of VRE on market-wide, annual average wholesale power energy prices, this report applies a simple fundamental model in each of the seven centrally organized U.S. wholesale power markets. The approach is transparent, consistent across all regions, and disentangles the relative influence of wind and solar, changes in natural gas prices, plant retirements and additions, electricity load, emissions regulations, and other factors.

In this model, for each ISO/RTO, annual average wholesale prices are based on intersecting a supply curve with net demand (demand net of wind and solar) in each hour and then averaging of the prices across all hours of the year (Figure 2). Electricity demand, wind, and solar vary by hour based on historical weather patterns (based on hourly data largely reported by the system operators). Hydropower and imports similarly vary by hour, though the hourly patterns are based on historically observed relationships between hydropower, monthly precipitation and net demand, or imports and net demand, respectively. The supply curve is developed by sorting individual generators in ascending order of variable generation costs. Fuel costs, the main contributor to variable costs, change by day for natural gas-fired units, by month for coal-fired units, and by year for other generators. Natural gas costs are based on trading prices at market hubs, while all other fuel costs are based on regional average production costs reported by the U.S. Energy Information Administration (EIA). Variable costs also include annual average costs of emissions permits—for carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_x)—where applicable. The heat rate of individual generators varies by month and historical year. Generator availability and capacity vary by season. In some instances, prices are not set by the marginal generator in the supply curve and are instead based on assumed penalty prices. Specifically, if the intersection of the supply curve and demand falls below the minimum generation level, based on nuclear and combined-heat-and-power capacity, prices are assumed to equal a negative bid price of -$3 to -$17/MWh, depending on the region. The negative bid prices are based on the actual observed average negative price in 2017 for each region. Alternatively, if the demand plus an assumed operating reserve margin of 5% exceeds estimated supply, prices are assumed to increase to a penalty price of $1,000/MWh.[21] This simple supply-curve model does not include resources such as storage and demand response. Storage is particularly challenging to capture in a simple supply-curve model owing to the importance of considering how decisions to charge or discharge storage in one hour will impact the ability to discharge in subsequent hours. Additional details on the data and assumptions associated with these supply-curve models are included in Appendix A.

[21] Simple assumptions are used here for operating reserves, negative prices, and penalty prices rather than developing very detailed assumptions for each region based on actual market rules. This decision is based on the limitations of the simple supply-curve model in capturing myriad factors that drive extreme prices and not wanting to convey a false sense of precision, particularly with respect to capturing extreme prices fully.

Figure 2. Illustration of the supply-curve method for estimating hourly prices based on the intersection of supply and net demand.

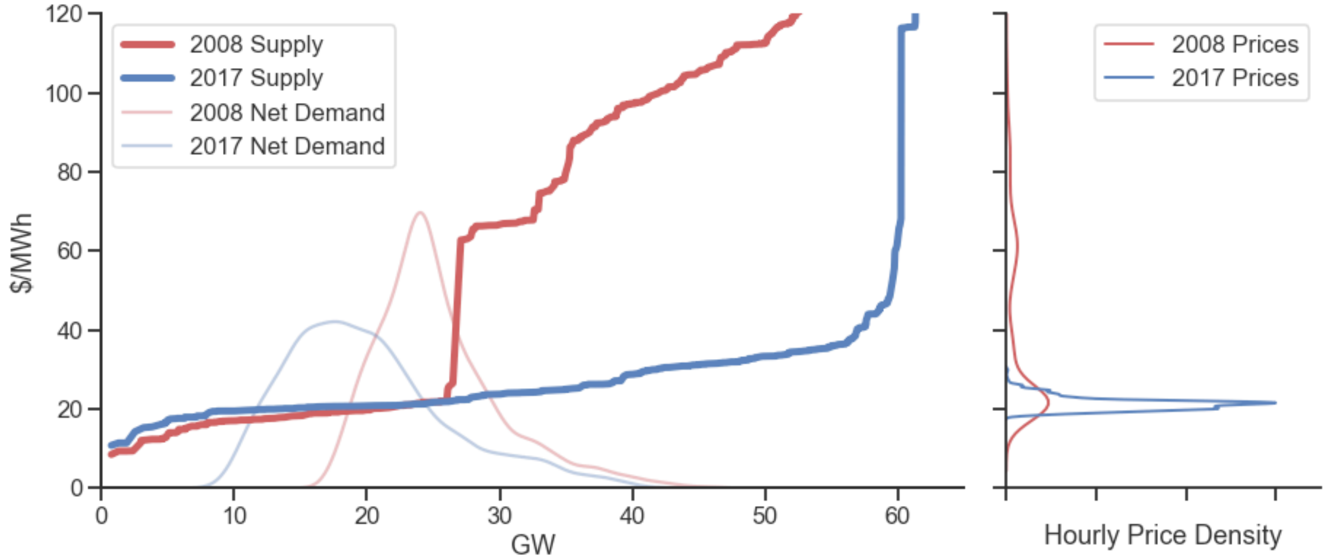
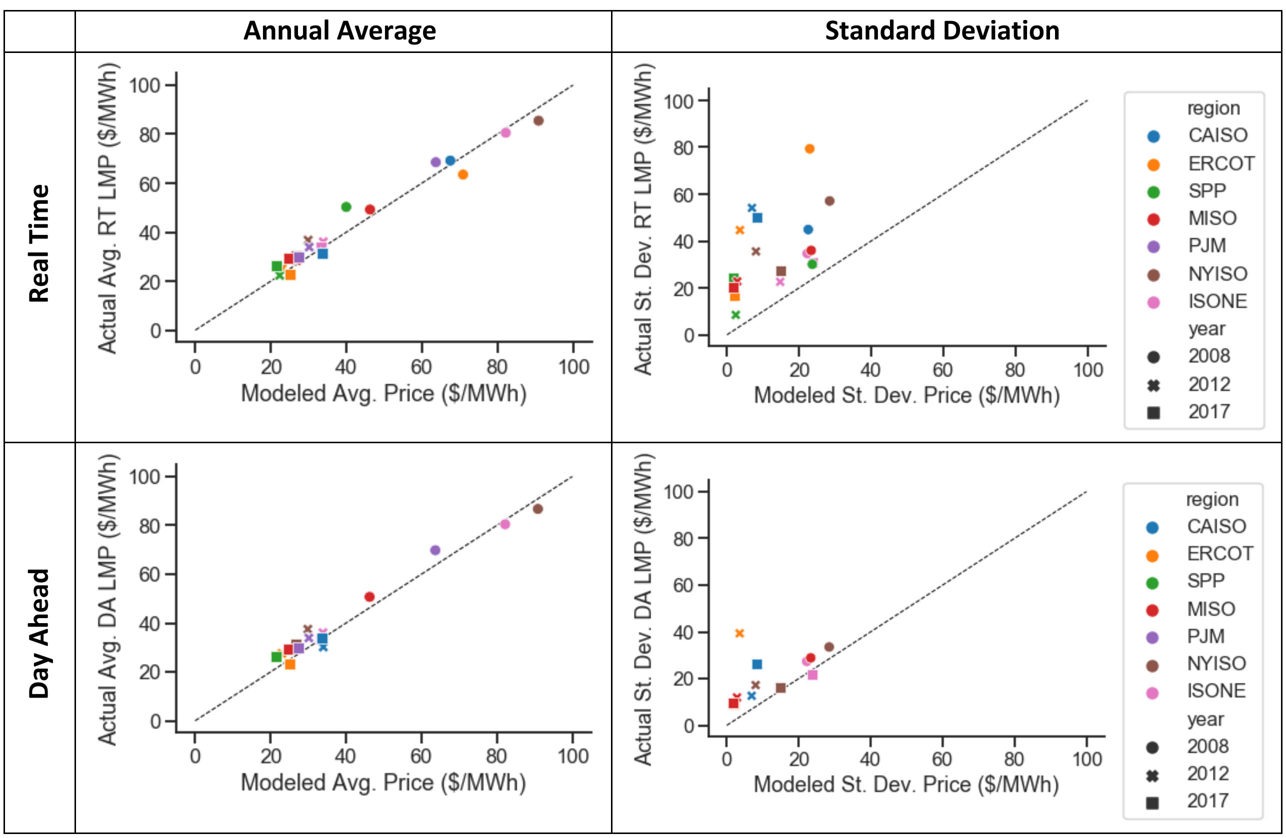


Figure 3. Comparison of modeled and actual RT (top) and DA (bottom) average annual wholesale power energy prices (left) and the standard deviation of wholesale prices (right) for different historical years and market regions.



RT = real-time; DA = day-ahead; LMP = locational marginal price

The modeled wholesale prices vary depending on the shape of the supply curve and the distribution of the net demand. Natural gas prices in particular can impact the shape and level of the supply curve. Figure 2, for example, shows that—with high natural gas prices in 2008—the supply curve had a distinct step between the variable costs of coal-fired plants (up to about 27 GW of supply) and the variable costs of natural gas-fired plants. With 2008 natural gas prices, relatively small changes in demand, variable generation, or thermal-plant retirements or additions could shift the supply curve or net demand distribution in ways that significantly impacted wholesale prices. By 2017, however, the lower natural gas prices eliminated the large step change in the supply curve between coal-fired and natural gas-fired plants. With this flatter supply curve, relatively small changes in demand, variable generation, and thermal capacity had much more muted impacts on wholesale prices.

By fixing all parameters to their historical levels in 2008, 2012, and 2017, the simple model can reasonably replicate average annual wholesale energy prices at major trading hubs in each centrally organized power market (Figure 3).[22,23] In contrast, comparing the standard deviations of modeled hourly prices to those of the actual hub prices shows that the model is not as effective in representing hour-to-hour variability, though the variability of the modeled prices is closer to the variability of DA prices than it is to the variability of RT prices. In particular, the distribution of prices from the simple supply-curve model tends to be much narrower than the distribution of actual RT prices (i.e., the model shows fewer very high-price or low-price events than the number of events observed in actual RT prices; see Appendix A). This result is expected, because the model does not account for many of the flexibility attributes and constraints embedded in real markets. It is also why this analysis uses the model solely to assess the impact of various drivers of market-wide average annual wholesale prices, and not to explore geographic and temporal variability in those prices.

More specifically, this analysis uses the simple supply-curve model to estimate the impacts of changing one factor at a time between historical years across all ISOs/RTOs. For example, the impact of wind or solar on average wholesale prices in 2017 is estimated by changing the wind or solar to its 2008 level while keeping all other factors constant at their 2017 levels. By individually changing each factor from its 2017 level to its 2008 level, this analysis can disentangle the relative contribution of different factors to the observed decline in average annual wholesale prices between 2008 and 2017. The same approach is applied over the 2012–2017 period as well, also to explore the relative contribution of different drivers.

---

[22] Because the simple supply-curve model is a "fundamental" model, which builds up the prices from characteristics of supply and demand, the actual prices from major trading hubs are used only to validate the model, not as parameters in the model itself. That said, refinements to the simple supply-curve model were needed to improve the agreement between the average modeled and average actual prices. In PJM, for example, actual average prices at the "Western" hub could not be replicated without splitting PJM into two regions, as described more in Appendix A.

[23] Some of the markets saw major design changes between 2008 and 2017. In particular, several markets did not have centrally organized wholesale markets in the earlier years of this period. As such no comparison of DA and modeled prices was possible for 2008 for CAISO, ERCOT, and SPP, and for 2012 for SPP. All markets had DA and RT prices by 2017. Another important market evolution for CAISO was the introduction of the Energy Imbalance Market (EIM), which enabled RT balancing with utilities outside of CAISO starting in 2015. The fundamental model considers only CAISO generation and loads and does not include the broader EIM.

One limitation of this approach is that average wholesale prices are not a linear function of all the factors that affect prices. Owing to these non-linearities, the sum of the price impacts from changing factors individually will be different than the aggregate impact from changing all factors simultaneously. This analysis therefore also explores the magnitude of the interaction between factors and the implications of this interaction for disentangling the relative contribution of different factors to the observed price decline. The interaction term only captures differences between changing factors individually relative to the impacts of changing all factors simultaneously; it does not capture impacts of factors that might be missing from the model that would lead to differences between modeled and actual prices (shown in Figure 3). As a result, even a model that more accurately estimates wholesale prices would still likely face the same issue of non-linear interactions inhibiting the ability to disentangle the impacts of individual factors.

Finally, EIA projections of key factors—including fuel prices, wind and solar growth, generation additions and retirement, and demand—are input to the supply curve model to estimate future average wholesale prices in 2022. By again changing factors individually, this analysis can estimate the relative impact of these changing factors on wholesale power prices in the relatively near future.

3.2 Impact of VRE growth on annual average wholesale prices

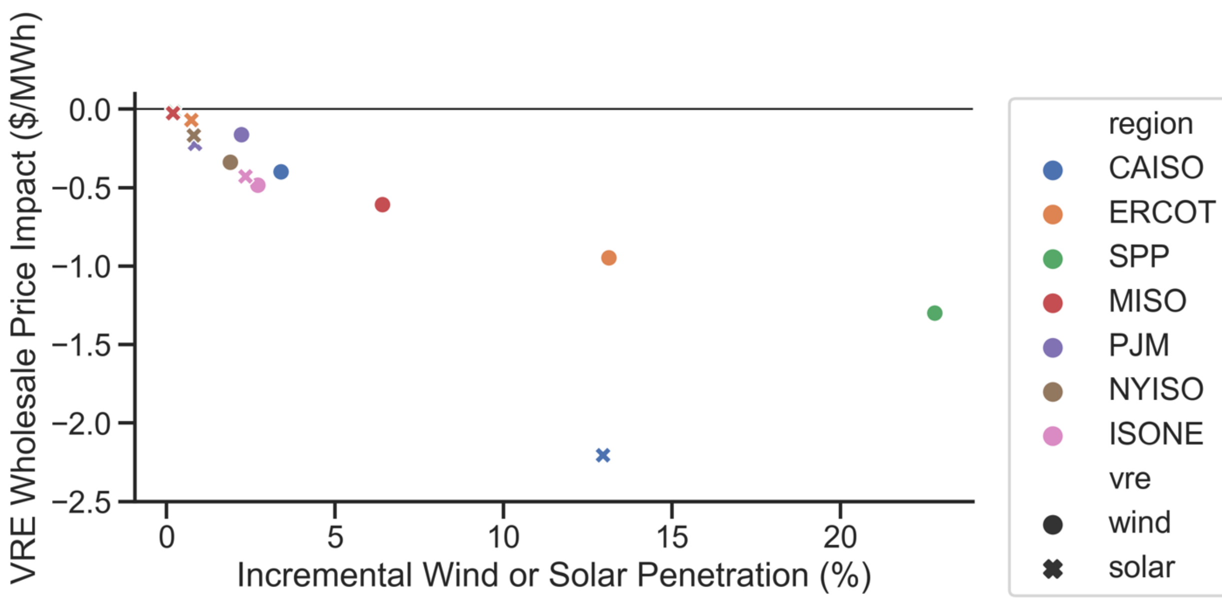
With low natural gas prices and a relatively flat supply curve in 2017, the impact of VRE growth between 2008 and 2017 on average wholesale prices was relatively small in all seven markets (less than -$2.2/MWh).[24] The magnitude of the estimated impact primarily depends on the incremental level of VRE penetration, where a higher share of VRE leads to a greater impact on prices (Figure 4). Across all markets and types of VRE, each incremental increase in VRE penetration reduced average annual wholesale prices in 2017 by approximately $0.14/MWh/% penetration.

At low penetration (where annual generation from VRE is less than 5% of demand), the impact of wind and solar on average annual wholesale prices is similar across all markets. Even at higher penetrations (5%–25%), the impact of wind appears to depend more on the penetration level than on regional variations in the composition of the power system. The impact of higher solar penetration in the CAISO system, however, stands out as having a disproportionally large impact on average prices—perhaps foreshadowing greater impacts from solar in other regions as solar penetrations grow. The relatively greater impact of solar in CAISO relative to the similar share of wind in ERCOT is driven by solar more frequently shifting the net demand in the steeper part of the supply curve and therefore having a larger impact on prices with and without solar. The alignment with the steeper part of the supply curve is due to solar in California reducing net demand during summer afternoons, when marginal generators tend to be less-efficient peaker plants. Wind in ERCOT, on the other hand, is less likely to reduce net

[24] The impact of wind and solar were assessed individually rather than the combined impact of wind and solar, because the impacts of wind can be distinctly different from the impacts of solar. Most regions tend to be dominated by one technology or the other, with the exception of CAISO, which has significant wind and solar. The combined impact of wind and solar would be about -$2.6/MWh in CAISO.

demand on summer afternoons and more likely to reduce it in the evening when the supply curve is flat. More generally, the impact of VRE on wholesale prices is expected to be greater where VRE generation tends to be more concentrated at times when the supply curve is steep. The supply curve tends to be steeper at times of high net demand (e.g., summer afternoons and evenings in many markets), times when marginal fuel prices are high (e.g., periods with high natural gas prices due to high gas demand and limited capacity in the U.S. Northeast), or even when the net demand is very low and negative bids become marginal.

Figure 4. Impact of VRE growth between 2008 and 2017 on annual average wholesale power energy prices in each ISO/RTO.

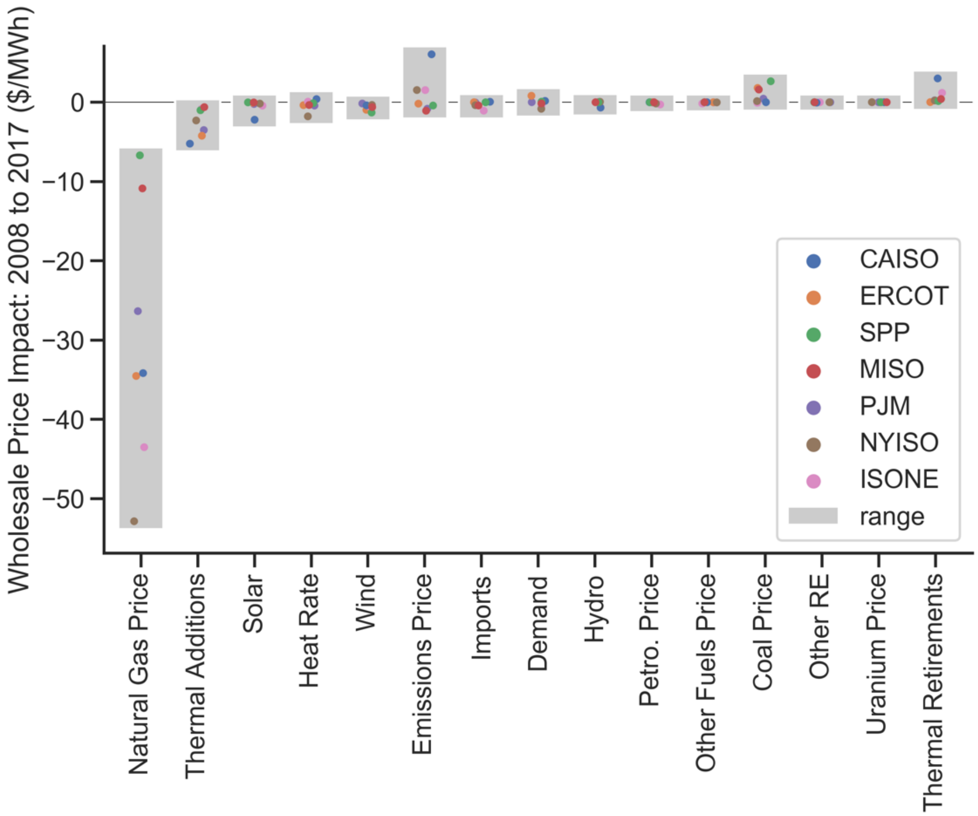


VRE = variable renewable energy

3.3 Impact of other factors on annual average wholesale prices

This analysis applies the model to possible price drivers other than VRE, demonstrating that—across all seven markets—changing natural gas prices had the largest impact on wholesale electricity prices between 2008 and 2017, far greater than the impact of VRE or any other factor (Figure 5). Not surprisingly, the impact of changing natural gas prices was highest in markets where natural gas-fired generators remained marginal in the supply stack even with higher gas prices (CAISO, ERCOT, PJM, NYISO, and ISO-NE). In contrast, the impact of high natural gas prices in 2008 (compared with 2017) on wholesale electricity prices was more muted in SPP and MISO, where it is likely that coal plants were often the marginal units owing to their relatively low variable costs.

Figure 5. Average wholesale power energy price impacts of various factors that changed between 2008 and 2017 across all markets.[25,26]



Second-tier price influences included growth in VRE, thermal power plant additions and retirements, coal prices, emissions prices, heat rates, demand, imports, and hydropower. Additions of new thermal power plants between 2008 and 2017 lowered wholesale prices, particularly in CAISO, ERCOT, PJM, and NYISO. Retirements of existing power plants, on the other hand, increased prices, particularly in CAISO.[27] The CAISO power plants that retired over this period included the 2.3-GW SONGS nuclear

---

[25] The individual factors are ordered along the x-axis, with factors having the most negative impact on wholesale prices on the left and least negative impact on the right.

[26] The wholesale price impacts of wind and solar are not combined into a single factor, because it appears there are distinct differences between the impacts of these two types of VRE.

[27] The impact of thermal retirements on wholesale prices with 2017 as a base year is measured based on comparing the wholesale prices calculated for 2017 with the wholesale prices if no thermal retirements occurred between 2008 and 2017 (in effect simulating the price impacts of the excess generation). In contrast, the effect of thermal retirements on wholesale prices with 2008 as a base year is simulated by comparing wholesale prices calculated for 2008 with the wholesale prices if all generation that retired between 2008 and 2017 were removed from the generation stack. As with other factors, larger effects are found when using 2008 as the base year (described in Appendix C). In this case, the impacts are not only due to the steeper supply curve with higher natural gas prices, but also they are due to the asymmetry associated with the consequences of too little generation capacity (leading to some periods with very high scarcity prices of $1,000/MWh) compared with too much generation capacity (leading to only slightly lower prices). Thus, the impacts of thermal retirements have small impacts on prices with a base year of 2017 and much greater impacts with a base year of 2008. One exception is that CAISO sees large price impacts of thermal retirements even with a base year of 2017. This is due to one of the major retirements over this period being the SONGS nuclear plant, which contributes to some periods with very low prices at the assumed negative bid of -$10/MWh in CAISO.

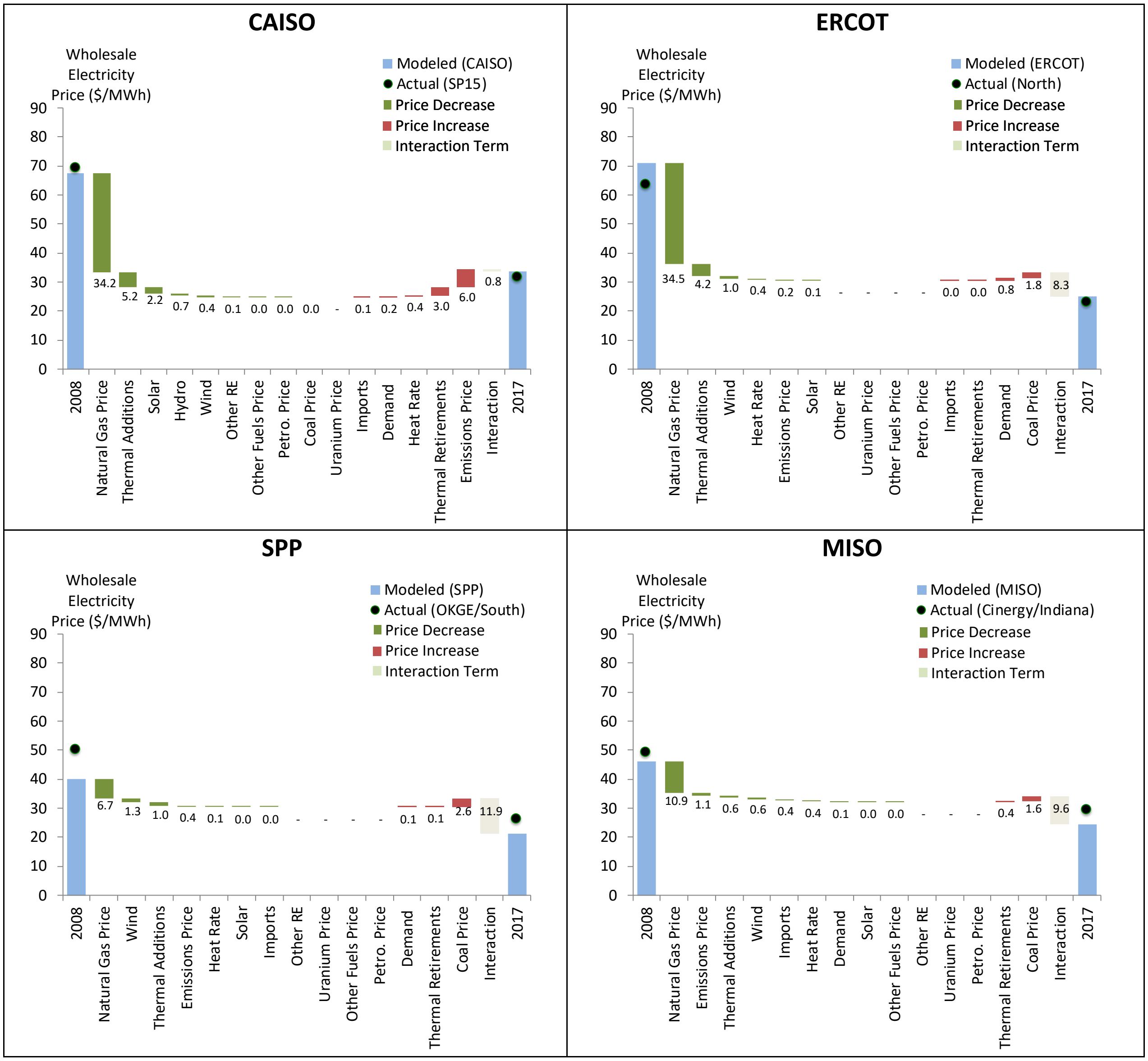
power plant and more than 7 GW of natural gas-fired power plants. Higher coal prices in 2017 compared to 2008 increased prices in SPP, MISO, and ERCOT. Changing emissions prices between 2008 and 2017 had a mixed impact on wholesale electricity prices. NO_x and SO_2 prices declined over this period, lowering wholesale prices in markets like MISO and PJM. On the other hand, the variable costs of fossil-fuel generators in CAISO, NYISO, and ISO-NE increased with the creation of emission permits for CO_2 in these markets; this is especially true for CAISO. Reductions in the heat rate of power plants (i.e., increases in power plant efficiency) decreased wholesale prices, particularly in NYISO. Decreases in demand lowered wholesale prices in ISO-NE, while increases in demand increased prices in ERCOT. Changes in hydropower (captured by historical variations in precipitation) and imports (driven by monthly imports reported by EIA) similarly increased or decreased wholesale prices by small amounts. Changes in petroleum prices, uranium prices, and other fuel prices all had negligible impacts on wholesale prices, as did growth in forms of renewable energy (RE) other than wind, solar, and hydropower.

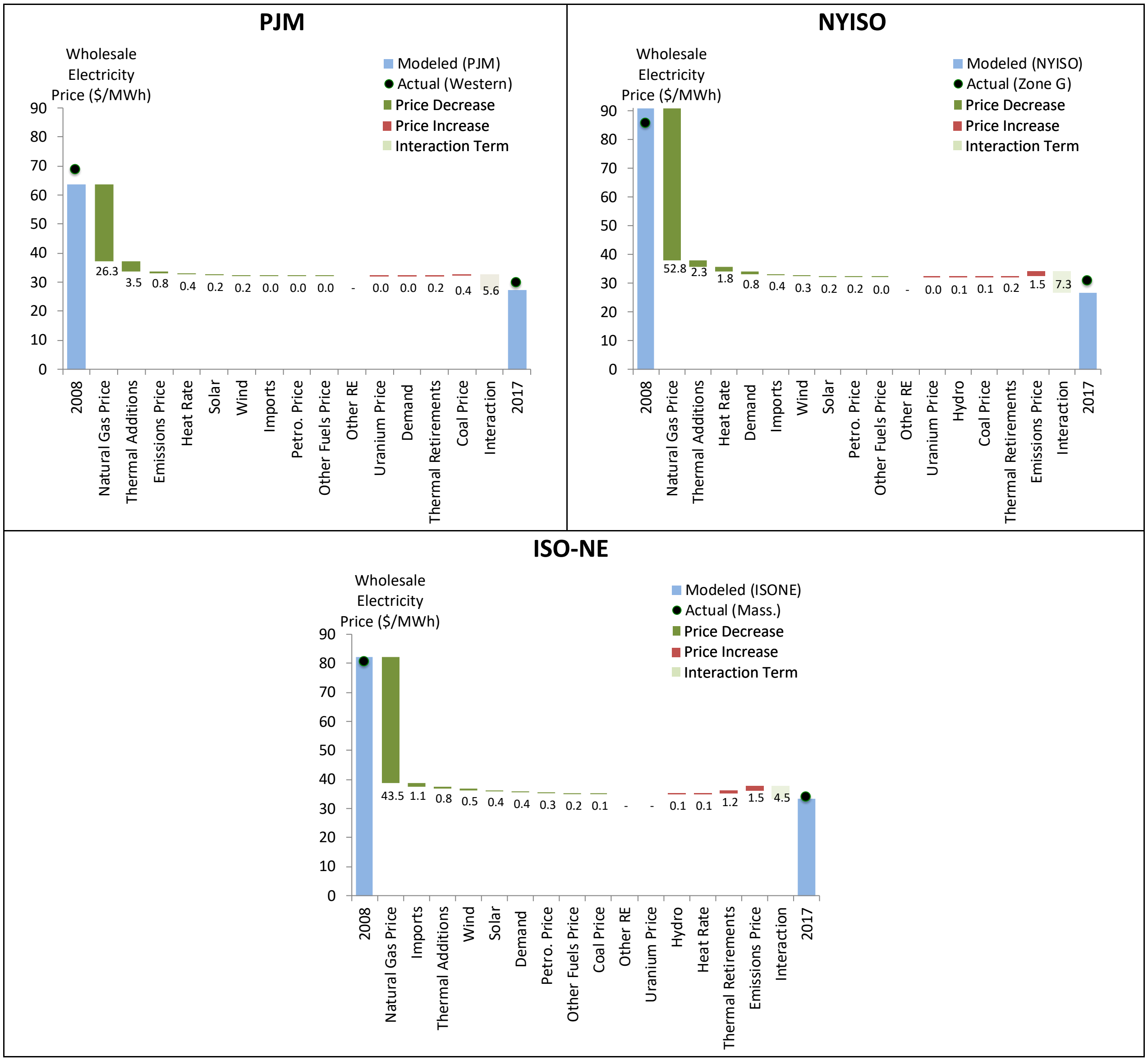
3.4 Drivers of the decline in wholesale power energy prices between 2008 and 2017

The relative contribution of each factor to the observed decline in wholesale prices between 2008 and 2017 is shown in Figure 6 and Figure 7. Owing to non-linearities, the sum of changes in wholesale prices from individual factors does not equal the change in prices from changing all factors simultaneously, leading to an interaction term, described further below.

Across all markets, the largest individual contributor to the decline in average annual wholesale prices between 2008 and 2017 was the fall in natural gas prices over the same period. Of the second-tier factors, some offset each other. For example, the decrease in wholesale prices in CAISO, MISO, and ISO-NE due to thermal generation additions was largely offset by the increase in prices due to retirements. In the other markets, however, the price reduction from thermal generation additions was larger than the price increase associated with retirements, leading to a net reduction in wholesale prices. In CAISO, NYISO, and ISO-NE, meanwhile, the decline in wholesale prices due to wind and solar was smaller than the increase in prices due to CO_2 emission permits.

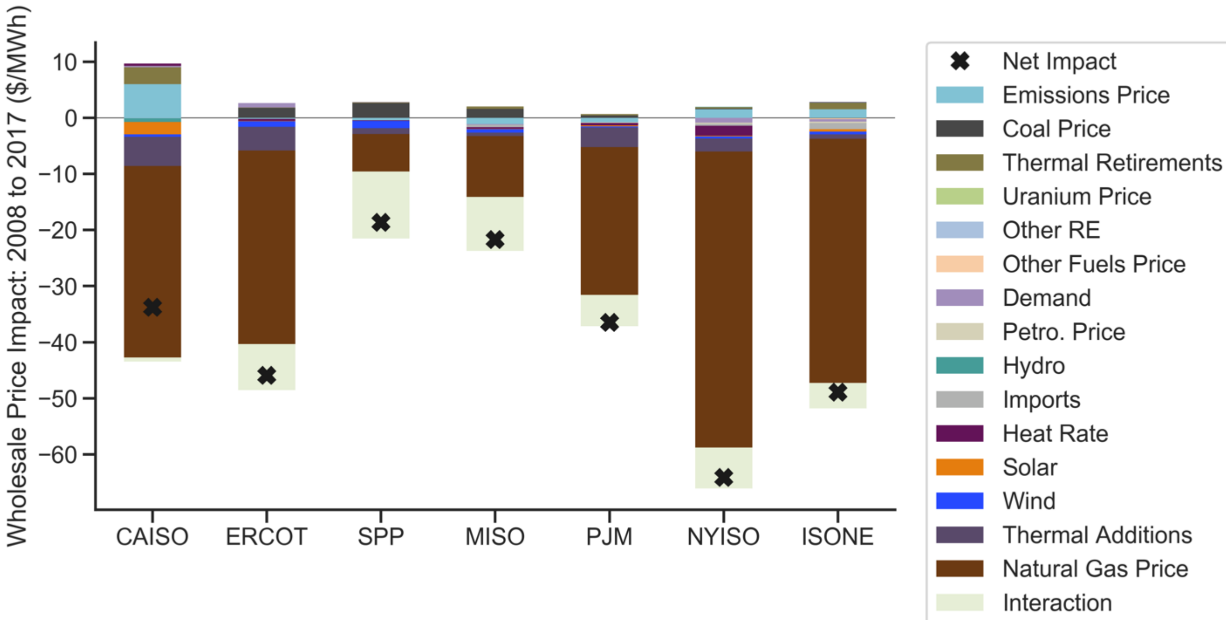
Figure 6. Relative contribution of different factors to the observed wholesale power energy price decline between 2008 and 2017 for each ISO/RTO.





RE = renewable energy

Figure 7. Summary of wholesale power energy price impact of various factors that changed between 2008 and 2017 across all markets.



RE = renewable energy

The large interaction terms relative to the overall decline in wholesale prices in some markets, particularly SPP and MISO, illustrate limits on the ability to disentangle the relative contribution of individual factors to the observed decline in wholesale prices. In SPP, for example, summing the impacts of all individual factors leads to a net price decline of $6.7/MWh, whereas changing all of the factors simultaneously leads to a price decline of $18.6/MWh. Owing to the interaction of multiple factors, the combined impact of each individual factor understates the combined price decline by $11.9/MWh. One source of interactions between multiple factors is due to changes in the net demand at the same time as changes in the slope of the supply curve, as explained in Appendix B.

In some cases, the strong interactions are largely attributed to interactions between increasing wind and changes in the slope of the supply curve due to changes in natural gas prices. Again using the example of SPP, the sum of the individual contributions of wind and natural gas to wholesale prices was $8.0/MWh, while the impact of changing wind and natural gas simultaneously was $14.9/MWh. The interaction of wind and natural gas is therefore almost two thirds of the overall interaction observed in SPP. Similar interactions between wind and natural gas were observed in ERCOT and MISO. As explained in Appendix B, interactions were less likely to occur when changes in natural gas prices simply shifted the supply curve up or down without significantly changing the slope. This situation often occurred when natural gas-fired generation was primarily the marginal generator over the year, irrespective of the natural gas price (e.g., CAISO).

Another consequence of interactions between factors is that estimates of the magnitude of the wholesale price impacts of individual factors depend on the choice of base year. The previous results began with the system as it was in 2017 and changed one factor at a time to its 2008 levels. For most regions, the low natural gas prices in 2017 meant that the supply curve was relatively flat, muting the impacts of various factors on wholesale prices. Alternatively, the analysis could have started with the system as it was in 2008 and changed individual factors to their 2017 levels. In this case, the considerably steeper supply curve in 2008 amplifies the impact of individual factors. For example, had things remained the same as in 2008, with a very steep supply curve in many regions, the impact on average prices of increasing VRE from 2008 to 2017 levels could have been as much as five times higher (a price decrease of up to $12.5/MWh instead of $2.2/MWh). Not only would VRE impacts have been greater, but also the impact of nearly all other factors would have been greater (Appendix C). Using a 2008 base year therefore overstates the contribution of individual factors, and it leads to an interaction term with the opposite sign.

The impact of VRE on average wholesale prices found in the previous literature (Table 1) is sometimes larger than the maximum impact of $2.6/MWh found in this analysis. In some cases, this can be explained by a different choice of base year. Haratyk (2017), for example, uses a 2008 base year and changes individual factors to their 2015 levels. In other cases, the period for the analysis includes years with higher gas prices and therefore a steeper supply curve. Quint and Dahlke (2019) find that the marginal impact of wind in MISO has declined with time as the supply curve has flattened. In other instances, of course, differences may be caused by the use of a simplified fundamental model, as opposed to regression models used in much of the other literature. Specifically, the simplified supply-curve model may not be fully capturing price impacts that occur at the tails of the distribution, a possibility supported by the model's relative underperformance in estimating the volatility in hourly pricing. Finally, differences may exist owing to improper or imprecise methods used in some of the previous literature, or because of inaccuracies in interpreting the results of that literature as presented in Table 1.

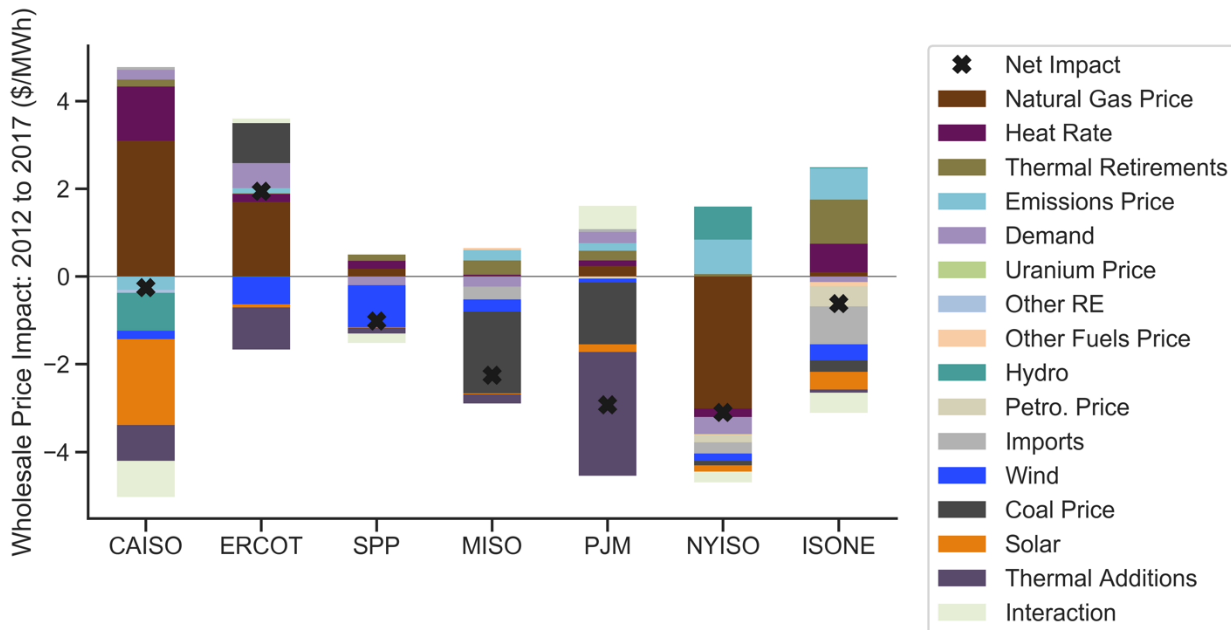
3.5 Post shale-gas boom price impacts: 2012 to 2017

Since 2008, annual average natural gas prices have fallen and remained at much lower levels, whereas shares of VRE generation have expanded rapidly in some markets. Here the analysis examines the relative impacts of different factors on wholesale prices over a period with low gas prices and relatively stable wholesale prices: 2012–2017. The results of the analysis, conducted in the same fashion as the earlier results for 2008–2017, are presented in Figure 8.

Overall, the net impact of all factors considered was to either modestly increase (ERCOT) or modestly decrease (all other regions) annual average prices. Even though natural gas prices were on average much lower in 2012 than in 2008, natural gas prices were still the largest driver of changes in wholesale prices in some regions from 2012 to 2017. In CAISO and ERCOT, natural gas prices increased between 2012 and 2017 increasing wholesale prices. In contrast, natural gas prices decreased in NYISO between 2012 and 2017 thereby reducing wholesale prices.

Factors that decreased prices on par with the estimated VRE impacts include thermal generation additions (PJM, CAISO, and ERCOT), decreases in coal prices (PJM and MISO), and more precipitation and therefore hydropower production (CAISO). Factors other than natural gas price changes that increased wholesale prices include higher coal prices in ERCOT, less precipitation and therefore less hydropower production in NYISO, marginal combined-cycle units in CAISO and ISO-NE that were less efficient[28] in 2017 than in 2012, generation retirements in ISO-NE, higher emissions prices in NYISO and ISO-NE, and increased demand in ERCOT.

Figure 8. Price impact of various factors that changed between 2012 and 2017 across all markets.



RE = renewable energy

3.6 Outlook for wholesale power energy prices and price drivers to 2022

EIA modeled projections[29] of demand, VRE growth, thermal additions, thermal retirements, and fuel price changes (along with regional projections of changes in CO_2 emissions prices[30]), were input to the supply curve model to estimate changes to wholesale electricity prices between 2017 and 2022 for all seven markets (Figure 9).[31] The major contributors to the increase in wholesale electricity prices vary by region, though EIA's modeled projection of the increase in natural gas prices is consistently one of the

[28] These changes in efficiency between years are based on changes in the heat rate of individual plants. Overall, the fleet of combined-cycle units has become more efficient over time as new units with high efficiency have been added.
[29] All EIA projections are based on the *2018 Annual Energy Outlook* (AEO) reference case (EIA 2018b). Details of EIA's projected changes are included in Appendix D.
[30] EIA does not present regional CO_2 emissions prices in the AEO. CO_2 emissions price assumptions from the California Energy Commission for CAISO (CEC 2018) and RGGI prices from NYISO for ISO-NE and NYISO (Cohen 2018) were used instead.
[31] As described earlier, the interaction term represents the difference between the sum of individual impacts and the impact of changing all factors simultaneously. It does not represent any differences between factors captured in the model and factors that might be left out of the model that lead to inaccuracies relative to actual prices. As such, an interaction term can be estimated for future prices in the same way that the interaction term is estimated for historical prices.

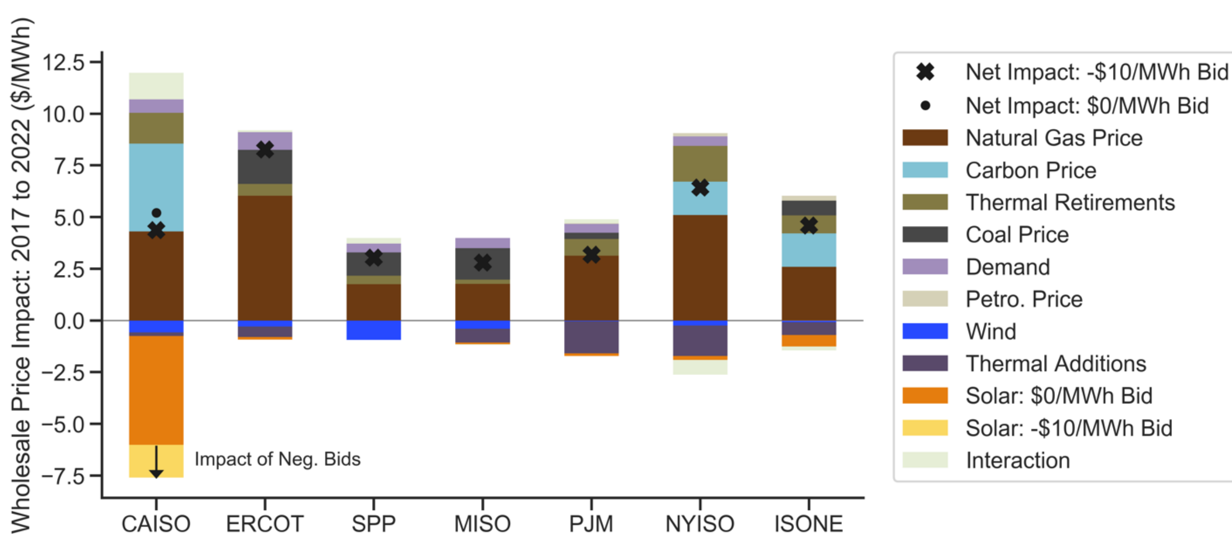
largest contributors. Increases in carbon prices in California and the Regional Greenhouse Gas Initiative (RGGI), as projected by planners in each of those regions, contribute to the increases in wholesale prices in CAISO, ISO-NE, and NYISO. EIA's modeled projection of increases in coal prices leads to notable increases in wholesale prices in MISO, ERCOT, and SPP. The increase in prices due to EIA's modeled projection of the retirement of thermal generation is substantial in CAISO and NYISO. Finally, EIA's modeled projection of increases in electricity demand increases wholesale prices modestly in most regions.

EIA's modeled projection of growth in VRE, on the other hand, mitigates the price increases, particularly in the case of solar growth in California. EIA's modeled projection of VRE growth results in a doubling of the solar penetration in California between 2017 and 2022, leading to several instances in the simple supply-curve model where net demand is less than minimum generation levels for nuclear and combined-heat-and-power units. Prices in these hours are therefore set by the assumed negative bid price for curtailing renewables. Because this future negative bid price is uncertain, the CAISO results are shown both assuming curtailment occurs at a price of zero and assuming curtailment occurs only when prices are below -$10/MWh.

The estimated impact of solar on wholesale prices in California far exceeds the anticipated impact of wind and solar in all other markets, even with solar curtailment assumed to occur at a price of $0/MWh. In most other regions, the decrease in average wholesale prices from wind and solar is on par with or less than the decrease in prices due to thermal generation additions.

These results are based on a simple supply-curve model and EIA's reference case modeled projections for the change in various possible price drivers to 2022. The results should not be construed as precise forecasts for future regional wholesale prices or price trajectories. In particular, the lack of storage in the simple supply-curve model will tend to overstate the magnitude of the impact of growth in solar.

Figure 9. Average wholesale power energy price impact of various factors that are expected to change between 2017 and 2022 across all markets.



Many factors can impact generation expansion and retirement decisions—including expansion of VRE—across U.S. markets, making it difficult to rely on only one source for future projections. Projections from other sources (e.g., BNEF 2018) include considerably greater wind and solar deployment in most markets than does EIA's reference case by 2022. One major exception is that Bloomberg New Energy Finance (BNEF) projects less wind and solar growth in CAISO than projected in EIA's reference case. The BNEF projections for utility-scale solar and wind are more in line with planned projects cataloged in ABB's Velocity Suite, an electric industry data aggregation service. Analysis in Appendix E shows that using generation expansion and retirement projections for 2022 from ABB's Velocity Suite,[32] as an alternative to the EIA's reference case, results in overall similar conclusions as presented above. The primary differences in the alternative case are smaller impacts of solar in CAISO and greater impacts of wind relative to impacts based on EIA's modeled projections, particularly in SPP, NYISO, and ERCOT. The greater impact of wind in the alternative case is in part due to more frequent negative prices with the growth of wind. Solar growth in CAISO still has the greatest impact on decreasing prices. However, other factors that tend to increase prices (e.g., natural gas prices, emission prices, and thermal retirements) are still overall greater, leading to a net wholesale price increase in each market between 2017 and 2022.

[32] Details of the alternative 2022 case using ABB Velocity Suite data can be found in Appendix D.

4. Impacts of VRE on Geographic and Temporal Variations in Wholesale Power Energy Prices

The previous section highlights the contribution of VRE to observed changes in average, annual market-wide wholesale prices at the ISO/RTO level. Because that analysis is based on a simple supply-curve model, it cannot capture more granular changes in the distribution of prices, changes in the temporal patterns of prices, and changes in the geographic patterns of prices. To complement that analysis, this section examines historical wholesale pricing trends and VRE impacts at smaller regional and local levels through analysis of historical patterns of nodal wholesale power energy prices, with a particular focus on temporal trends in pricing and especially negative wholesale prices. Nodes are specific locations in the power grid where prices for energy are established for generation or demand. Nodal wholesale power energy prices are commonly referred to as LMPs.

How wholesale prices change over time, such as during a day, can be of major importance to a current or prospective generator owner. For example, some types of generation are dependent on infrequent price spikes during peak demand times to earn much of their annual revenue, thus assuring economic viability for a resource that may also be needed to operate when VRE generation is not available or for reliability purposes.

Though the analysis briefly explores geographic trends in annual average prices and trends in the overall distribution of prices, the special focus on negative wholesale prices is motivated by the correlation between zero-marginal-cost generation (such as VRE) and the frequency of negative prices. Thus, tracking the incidences of negative prices, and the impacts of such prices, can provide insight into the impacts of VRE on overall wholesale prices and general market trends. Furthermore, while the choice of prices below $0/MWh is somewhat arbitrary, it is a threshold used commonly in other literature, and it signifies periods in which oversupply of generation is a challenge. However, not all incidences of negative prices originate from VRE, and the detailed nodal analysis conducted here can help separate VRE price impacts from the influence of other drivers. Finally, the nodal analysis in this section helps illustrate how negative prices have differentially occurred at pricing nodes associated with different types of electricity generators.

This section is split into five topical areas:

(1) Macro trends across the United States: Overall pricing trends, how negative prices vary across the United States and over time, the impact of negative prices on annual average prices and on different generator types, and the degree to which negative prices occur system wide or are more localized.
(2) Impact of wind on prices: The correlation between negative prices and wind power generation, and what other types of power plants are generating during negative-price hours.
(3) Impact of solar on prices: The impacts of solar on diurnal and seasonal pricing patterns and on negative prices in California, and examine other drivers of changes to pricing patterns.
(4) Hydropower contribution to negative prices: The role of hydropower in driving negative prices in

the Northwest.

(5) Transmission expansion and negative prices: Negative prices in two locations (ERCOT and Northern Illinois) before and after transmission expansion.

The analysis emphasizes hourly wholesale power energy pricing patterns at more than 60,000 pricing nodes across the United States, focusing on centrally organized markets. Some of the analysis includes DA prices, but the focus is primarily on RT prices where the impacts of VRE are more readily observed. DA prices are most relevant to inflexible plants that only sell power in the DA market and do not participate in RT balancing (e.g., nuclear and some coal units). RT prices, on the other hand, reflect the value (or cost) of generation deviating from its DA schedule to support (or hinder) real-time balancing between supply and demand.[33]

On average, DA market prices tend to track average RT market prices. For example, across a set of major trading hubs,[34] the average RT price was $2.5/MWh lower[35] to $0.6/MWh higher (8% lower to 2% higher) than the average DA price in 2017. As a result, even if negative prices are more common in the RT market than in the DA market, negative RT prices are anticipated to affect longer-term average pricing in the DA market (Bajwa and Cavicchi 2017). On the other hand, the volatility of RT prices is persistently higher than the volatility of DA prices. This higher volatility is expected, because fewer options are available in RT to resolve issues that appear after the close of the DA market, including generator and transmission outages, load and renewable forecast errors, and other unforeseen changes. Fewer options are available owing to the lead time necessary to start and stop units and limitations in the ramping capability of units. With fewer options available, RT outcomes that differ from DA expectations can lead to higher or lower prices in RT and hence higher volatility. Finally, all of the ISOs/RTOs now use 5-minute markets for RT balancing, and FERC now requires RT settlements to occur over the same interval as used for dispatch. This analysis, however, is based on hourly averages of those RT prices, in part because only hourly data are reported in the main data source, ABB's Velocity Suite. The volatility of 5-minute prices would likely be greater than the volatility of hourly averages of the RT prices.

---

[33] The participation of generation in RT balancing and volume of transactions varies between markets. CAISO, for example, reports that—in 2017—two thirds of the load could be met by generation that was self-scheduled in the RT market, and most of the self-schedules in RT were carried over from schedules resulting from the DA market (CAISO 2018, 102). The ERCOT market monitor estimates that 90% of the RT load was hedged through DA market purchases (Potomac Economics 2018a, ix). The PJM market monitor finds that, in 2017, 27.5% of the RT load was met through RT market purchases rather than through self-scheduled generators or bilateral contracts (Monitoring Analytics 2018, 126). SPP appears to have the greatest reliance on the DA market, with 98% of load purchased in that market (SPP 2018a, 107).

[34] This comparison of average RT and DA prices uses prices from SP15 (CAISO), North Hub (ERCOT), South Hub (SPP), Indiana Hub (MISO), Western Hub (PJM), Hudson Valley, Zone G (NYISO), and Mass. Hub (ISO-NE).

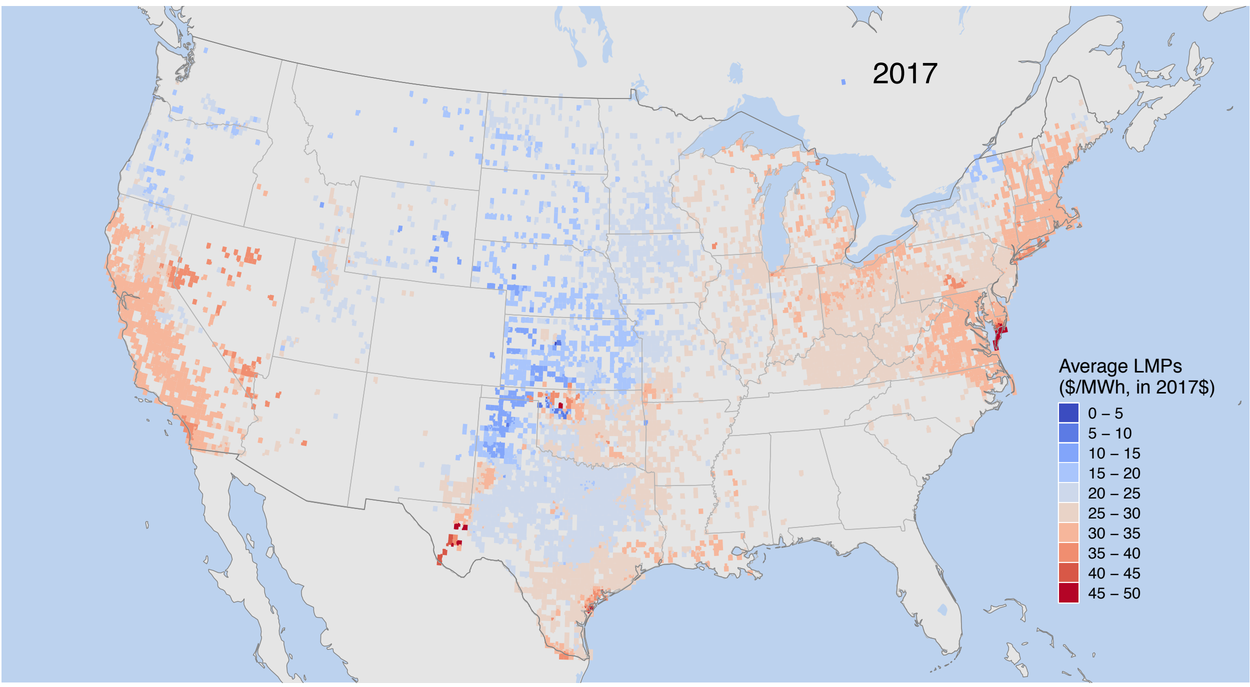
[35] In 2017, RT prices were the greatest amount below DA prices in CAISO at the SP15 trading hub.

4.1 Macro trends across the United States

4.1.1 Variation in real-time wholesale power energy prices between nodes

Average annual RT prices (LMPs) varied significantly from node to node across the United States in 2017 (Figure 10).[36] LMPs were lowest in the Midwest region, where wind generation has grown substantially, along with regions like Upstate New York and Northern Maine. LMPs were also low in the hydropower-rich Pacific Northwest, which also has substantial wind generation. LMPs in California, which has significant solar, were higher, as they were in most other regions of the country. The variation in average annual DA prices (not included in figure form) follows a similar geographic distribution as the RT prices, though with less variation from node to node.

Figure 10. Average RT LMP at each U.S. node in 2017.



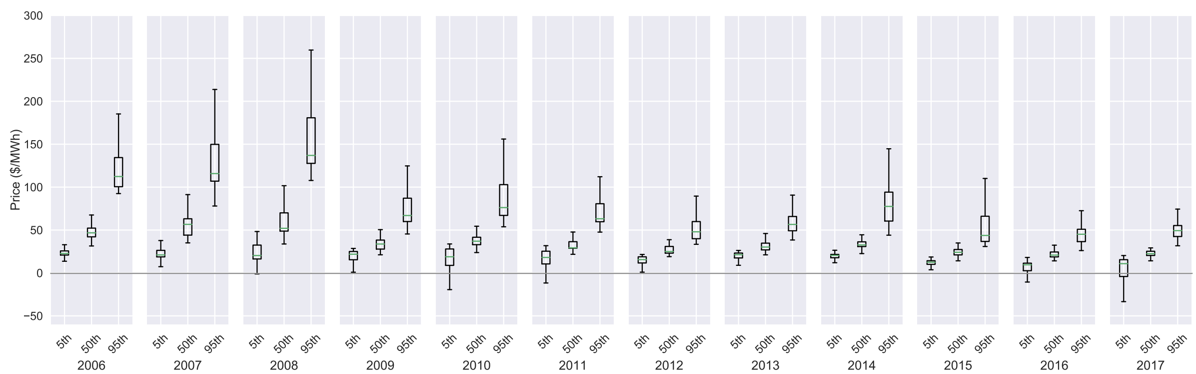
LMP = locational marginal price

Larger than the variation in *average* prices across different parts of the United States were the differences in *high* prices or *low* prices (Figure 11). From 2006–2016, the variation in high prices from node to node (represented by the 95th percentile of RT prices at each node for the respective year) was greater than the variation across nodes in median or low prices (represented by the 5th percentile of prices at each node). In 2017, however, the variation in low prices across nodes was greater than the variation in high prices. Further, more than a quarter of all pricing nodes had low prices that were negative in 2017. This suggests that recent growth in VRE may have had a greater impact on the low prices at some locations than it had on high prices or median prices. In part as a result, much of the

[36] Transparent LMPs are only available from the seven centrally organized wholesale power markets, which do not cover all parts of the United States. Particularly absent are the Southeast and the non-California West. The points in the West outside of CAISO are based on interface nodes with CAISO or, in more recent years, on EIM nodes. The points in the Southeast are based on interface nodes with PJM or MISO.

following analysis will focus on the growing share of negative prices and the degree to which VRE has been the driver of these negative prices. Negative prices are not uniquely interesting for understanding impacts of VRE on prices. Nonetheless, a price below $0/MWh is a convenient cutoff for signaling times when the supply of power exceeded demand at particular locations, and it is therefore a common feature in other discussions about the impact of VRE on wholesale power markets.

Figure 11. Distribution of RT LMPs across nodes for the 5th, 50th, and 95th percentile of prices within a node (in 2017$).



4.1.2 Increases in the frequency of negative prices

The percentage of nodes with negative RT prices during 5% or more of all hours grew rapidly between 2015 and 2017, though some years in the 2009–2012 period also had a substantial percentage of nodes with frequent occurrences of negative prices (Figure 12). As discussed below, the frequent negative prices in the 2009–2012 period were driven in part by limited transmission in the wind-rich region of West Texas prior to the CREZ transmission expansion as well as high hydropower levels in the West. The prevalence of nodes with negative DA prices during 5% or more of all hours followed a similar pattern, albeit with much smaller percentages of such nodes.

Figure 12. Percentage of nodes with more than 5% of hourly LMPs being negative.

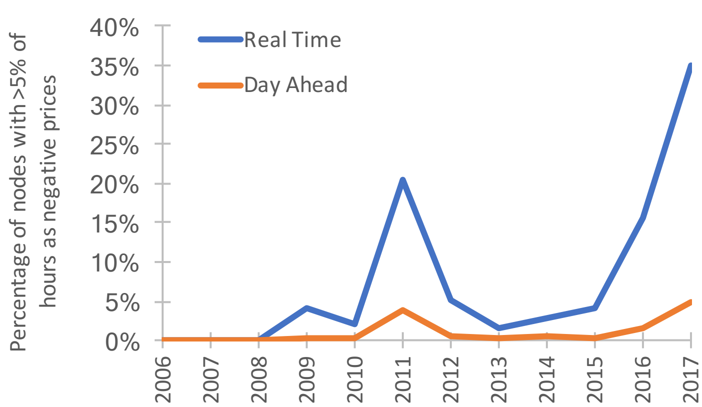
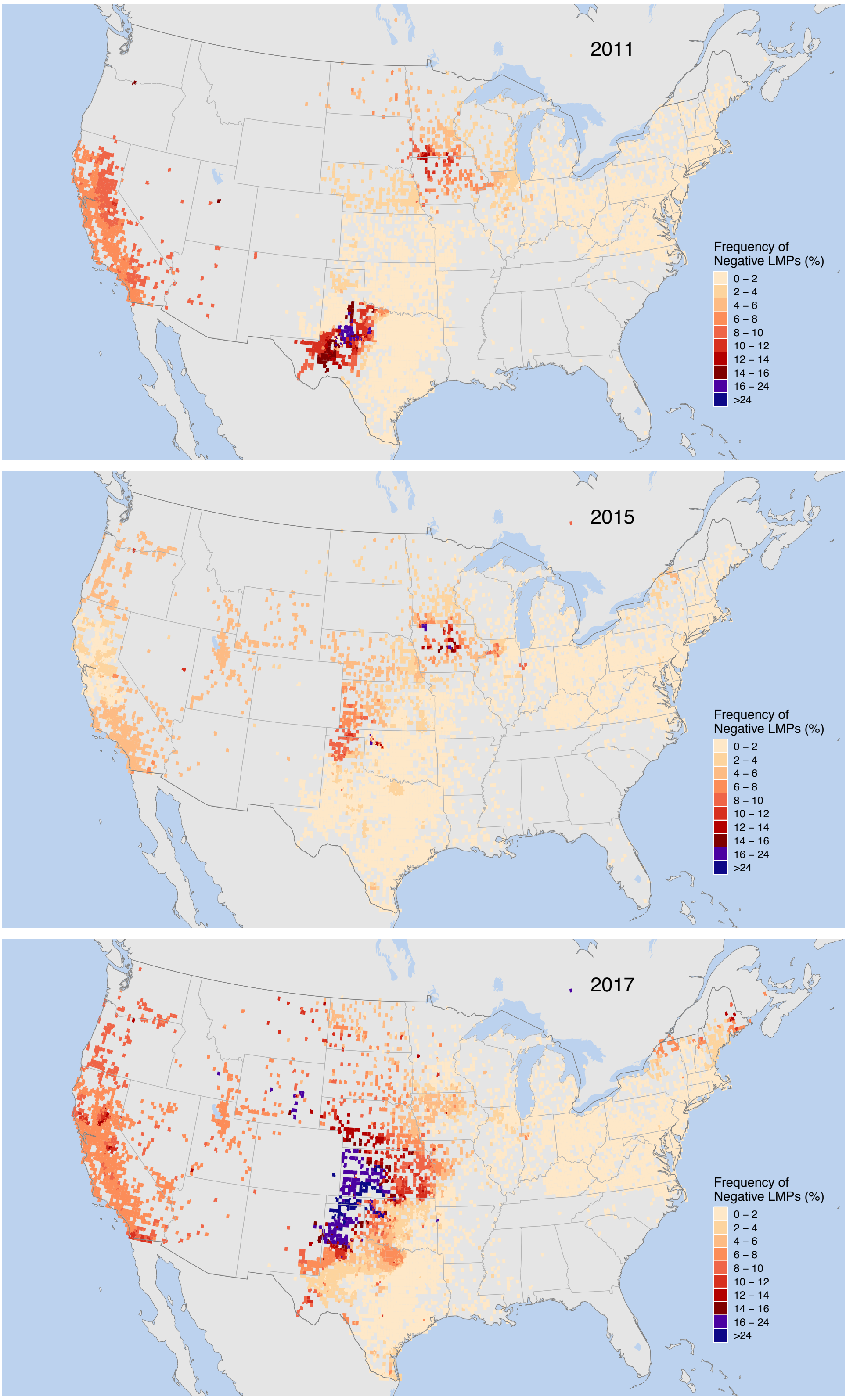


Figure 13. Frequency of negative RT LMPs at each U.S. node for 2011, 2015, and 2017.



LMP = locational marginal price

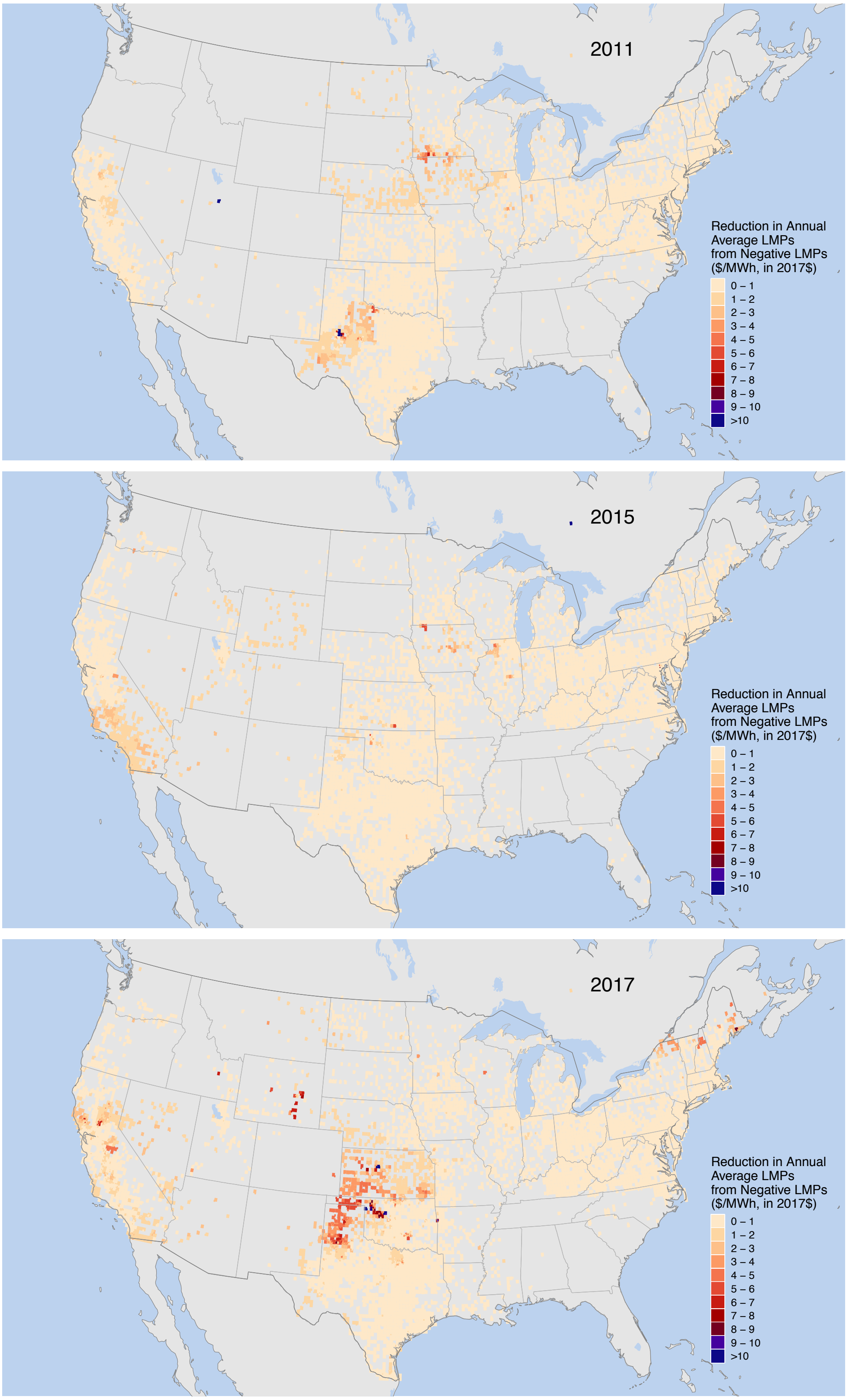
The price nodes with high percentages of negative LMPs tend to cluster in specific regions rather than being evenly dispersed (Figure 13). Often, the nodes with greater incidences of negative prices are near large amounts of VRE, though—as shown in subsequent parts of Section 4—VRE was not the only contributor to negative prices. In 2011, negative prices were clustered in the West Texas region of ERCOT, featuring large amounts of wind and constrained transmission (mitigated in 2013 through the CREZ transmission projects); the wind-rich region around Iowa, Southern Minnesota, and Northern Illinois; and throughout California and neighboring states. California had some wind and solar in 2011, though high hydropower and inflexible nuclear may have been greater contributors to negative prices in 2011 (see Section 4.3). By 2015, negative prices were less frequent in California and Texas, though they persisted in Iowa and neighboring areas. By 2017, negative prices were again very frequent in California, spilling out to other pricing nodes within the Energy Imbalance Market (EIM); pervasive across the wind-rich portions of SPP in Oklahoma, Kansas, and Nebraska; growing again across Texas; and starting to appear in the northern parts of New York, Maine, New Hampshire, and Vermont, where wind deployment has occurred in transmission-constrained areas. In some SPP areas in 2017, negative RT prices occurred in more than 20% of the hours of the year. In California, most nodes experienced negative prices in at least 6% of the hours of the year.

4.1.3 Impact of negative prices on annual average prices

Aside from the frequency of negative prices, the magnitude of negative prices was also larger in some regions than in others (Appendix F). The more negative the prices were, the more they brought down the annual average price. The reduction in annual average prices due to negative RT prices is shown in Figure 14. Comparing Figure 13 to Figure 14 shows that, while negative prices were common in relatively large regions, the impact of negative prices on average annual prices was often very limited (less than 2% in the vast majority of cases) except in a few "hot spots." The 2017 map illustrates the significant effect of negative prices on average prices in SPP in particular. The region between Northern New York and Northern Maine as well as certain parts of California also stand out. One interesting omission in 2017 is the disappearance of a hot spot in Northern Illinois. As discussed in Section 4.5, this region had seen steadily increasing negative prices with notable impacts on average prices until 2016, but in 2017 no such hot spot was apparent.

The regional clustering of negative prices means that not all generation has been equally affected. Negative prices led to the largest decrease in the average annual RT LMP at nodes where wind was located (negative prices decreased average prices at nodes with wind by about 6% on average in 2017) and increasingly at nodes near solar plants (by about 3% in 2017), as shown in Figure 15a. Nodes near hydropower plants have also been affected (also by about 3% in 2017). Pricing nodes near coal, gas, and nuclear plants saw less of a reduction in average annual RT LMPs due to negative prices (by about 1.5% in 2017), though those modest impacts have slightly increased over time. The sizable impact of negative prices in 2012, which primarily affected nodes near wind and hydropower, was largely due to frequent negative prices in the Pacific Northwest region during a high-hydropower year.

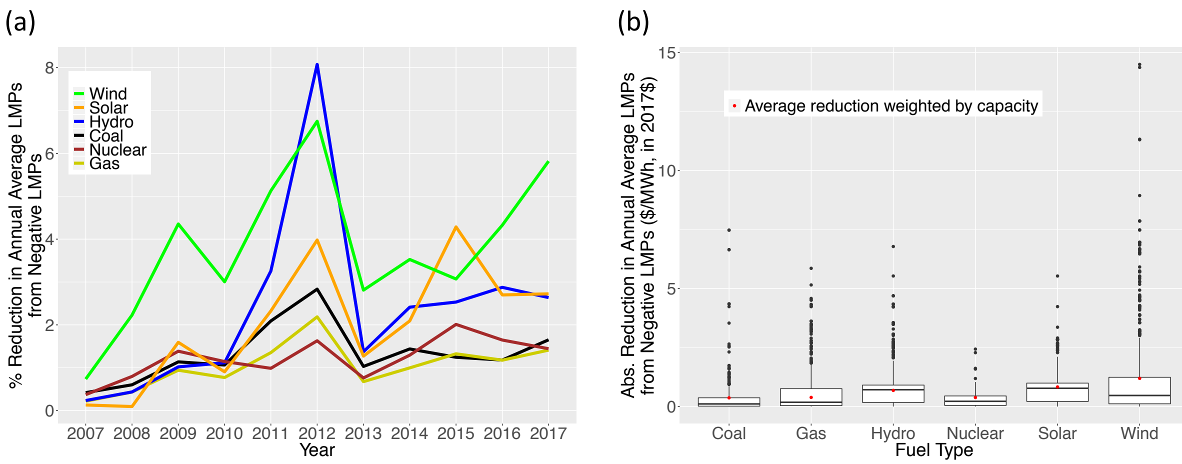
Figure 14. Impact of negative prices on average RT LMPs at each U.S. node for 2011, 2015, and 2017.



LMP = locational marginal price

For most power plants, negative prices reduced average annual RT LMPs by less than $1/MWh in 2017 (Figure 15b). For a few wind plants, however, negative prices decreased average annual RT LMPs by $5–$15/MWh. A small number of coal, gas, hydropower, and solar plants also saw reductions around $5/MWh. Most locations at which negative prices significantly reduced average annual LMPs were near wind, solar, or hydropower plants rather than near other generation types.

Figure 15. Decrease in average RT LMPs due to negative prices weighted by generation capacity associated with each node in (a) percent and (b) absolute terms.



LMP = locational marginal price

Even though incidences of negative prices signify the system value of power at particular times and locations, they do not always directly impact the revenues earned by generators. Some generators are hedged from market prices through long-term bilateral contracts (e.g., power-purchase agreements commonly used by wind and solar plants), and some interact only with the DA market and do not participate in RT balancing. Flexible generators that reduce their output from DA schedules may earn more revenues by responding when RT prices are negative. On the other hand, wind and solar generators that only participate in the RT market or have more RT generation than scheduled in the DA market will see a reduction in revenue with negative prices that are correlated with their output. For a merchant baseload generator that runs at a constant output, the impact of negative prices on potential revenues depends on how well reductions in average RT prices translate to reductions in average DA prices. Strong convergence between average DA and RT prices will lead to negative prices in the RT market impacting the revenues of merchant baseload generators.

4.1.4 Correlation of negative prices within each market

In 2017, the nodal negative prices in CAISO and ISO-NE were more tightly correlated over time and geography than those in ERCOT, MISO, PJM, SPP, and NYISO (Figure 16b). This suggests that events that drove negative prices in CAISO and ISO-NE in 2017 were more likely to be system-wide events, e.g., minimum generation levels. In contrast, events that drove negative prices in other regions in 2017 were more likely to reflect localized issues, e.g., transmission congestion.

To illustrate causes of system-wide or localized negative pricing events, this analysis examines the history of negative price correlation within four areas: CAISO, ISO-NE, ERCOT, and SPP[37] (Figure 16a). In CAISO, nodal negative pricing events correlated well with each other since 2011. This suggests that transmission within CAISO is relatively well developed and that surplus generation in one region of CAISO can affect all of CAISO, with limited cases of extreme congestion. This is true across years except 2015, when it appears in Figure 13 that negative prices were more common in Southern California and less common in Northern California. A likely contributor to the divergence between Northern and Southern California in 2015 was planned transmission outages on a major transmission path (Path 15) connecting the two parts of the state (CAISO 2015).

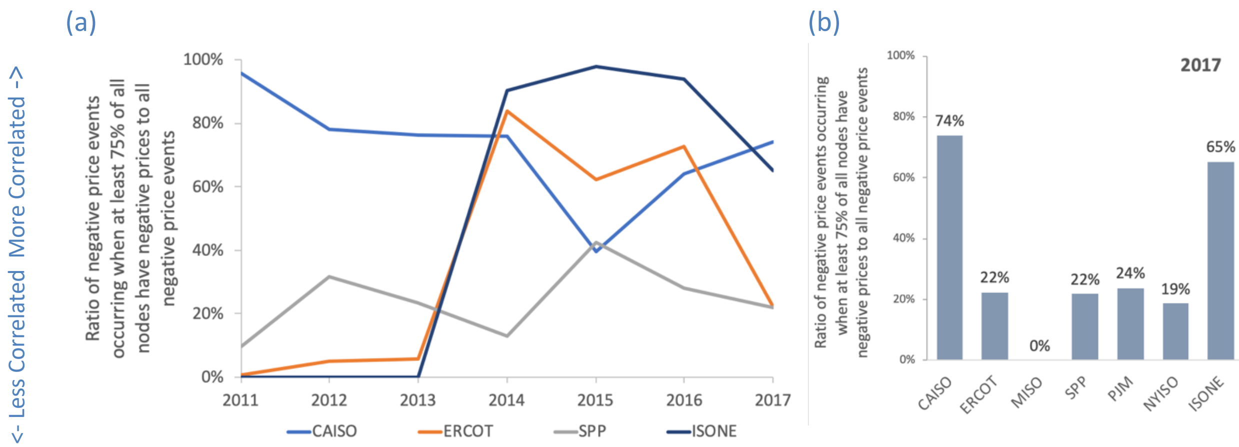
In ISO-NE, negative bids were not allowed prior to December 2014, and the relatively few instances of negative prices before this date could therefore only occur owing to local congestion (Robinson 2014). In contrast, after December 2014, nearly all of the negative price events simultaneously occurred at all nodes in ISO-NE. Low load and significant shares of generation from inflexible nuclear characterized these system-wide negative price events (see Appendix G). By 2017, there were increasing examples of negative prices occurring over a much smaller subset of nodes (less than about one quarter of the nodes in the system), primarily in the northern region where Figure 13 and Figure 14 show frequent and impactful negative prices. As shown in Section 4.2, these negative prices in the northern region of ISO-NE correlated with periods of high wind output. In addition to these somewhat confined negative prices, there were more than 100 hours of the year in 2017 (1.1% of the year) in which every node in the system had negative RT LMPs.

In contrast to CAISO and ISO-NE, negative pricing events in SPP have rarely been well correlated across the region's whole footprint. This could be due to transmission limits between the wind-rich region of SPP and regions with greater load, causing localized congestion-based negative prices.

Finally, negative pricing events in ERCOT have been well correlated in some years but not others. Specifically, negative pricing events were less correlated prior to the expansion of the transmission network in 2013 (CREZ), because transmission constraints limited negative pricing events to high-wind areas in West Texas. Immediately after the expansion of the transmission network, the smaller number of remaining negative pricing events were well correlated across ERCOT. However, as wind capacity continued to expand in West Texas, transmission began again to be a constraining factor, causing an increase in localized negative pricing events over the last several years.

[37] For clarity, the change in correlation over time is not shown for the other ISOs/RTOs. MISO has had low correlation over all years back to 2011, with at most 19% of negative price events occurring over at least 75% of nodes. PJM and NYISO had relatively few negative pricing events compared to the other markets. In PJM, the degree of correlation has been moderate in all years. NYISO had significant correlation in early years, but, as the number of negative pricing events has increased in more recent years, the correlation has simultaneously decreased.

Figure 16. Measure of correlation of occurrences of negative prices across an ISO/RTO (a) over time for a subset of ISOs/RTOs[38] and (b) in 2017 for all ISOs/RTOs.



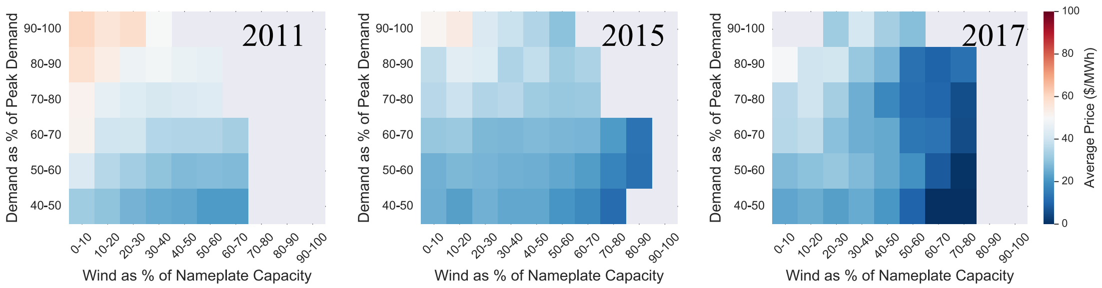
4.2 Impact of wind on real-time wholesale power energy prices

To further illustrate the role of wind generation in reducing wholesale power energy prices and in the incidences of negative prices, this analysis assesses the relationship between varying wind-generation levels and prices. Because prices are also affected by changing load levels, the effects of load and wind on prices are simultaneously examined. The region with the highest concentration of negative wholesale prices and the lowest average prices in 2017 is in the SPP footprint covering states in and around Oklahoma.

Figure 17 shows that average RT LMPs in the Oklahoma region of SPP were low at times when overall system load (i.e., electricity demand) was low and higher when load was higher.[39] More recently, and especially in 2017, the amount of overall SPP wind generation has also affected that relationship. Specifically, periods with high system-wide wind generation have been correlated with lower LMPs, particularly if the load was also simultaneously low. The impact of wind on average LMPs appears to have become stronger over time, such that average LMPs in 2017 were low when the wind was strongest even when system-wide load was relatively high. The SPP market monitor further highlights the role of wind being under-scheduled in the DA market relative to the RT market as a contributor to low RT prices during off-peak periods (SPP 2018a).

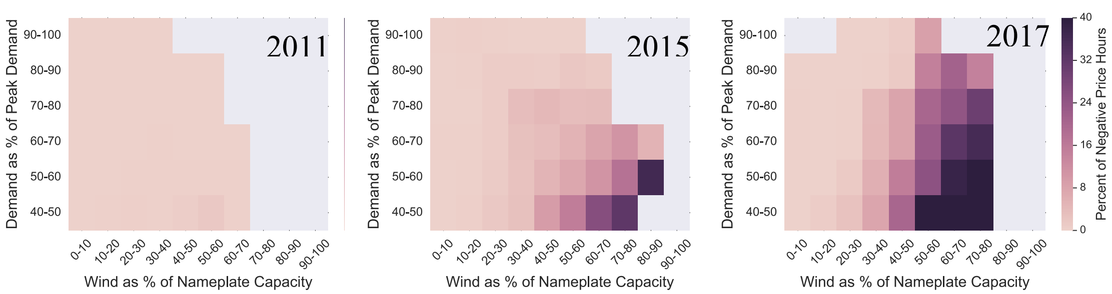
[38] Not all of the ISOs/RTOs are included here, because the figure would become cluttered without providing additional insight.
[39] Overall SPP load and overall SPP wind generation were used owing to limitations on the geographic resolution of the wind and load data.

Figure 17. Relationship between load, wind, and average RT LMPs around Oklahoma in SPP for 2011, 2015, and 2017.



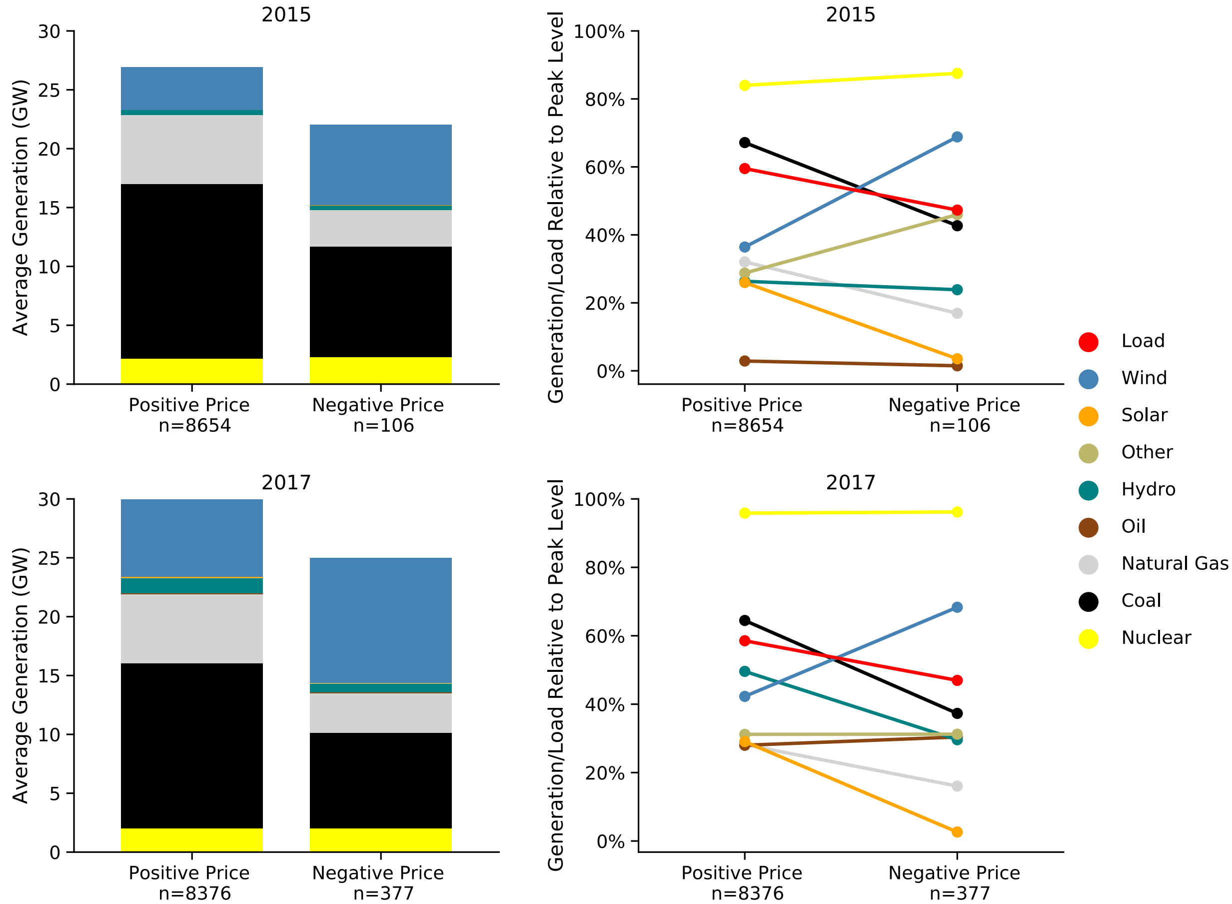
The lower average LMPs at times of high wind and low load were due to lower variable-cost resources being on the margin at those times. In some cases, the net demand would be low enough during these times to lead to negative prices (Figure 18). While negative prices were nearly nonexistent in the Oklahoma region of SPP in 2011, irrespective of system-wide load and wind generation, by 2017 negative prices occurred in nearly 40% of the hours when wind was generating above 50% of its nameplate capacity and load was below 50% of its peak level. Even when load was high in 2017, prices were sometimes negative when wind output was high. In contrast, in 2015, negative prices were unlikely to occur if the demand was high, regardless of the level of wind generation.

Figure 18. Relationship between load, wind, and negative prices around Oklahoma in SPP for 2011, 2015, and 2017.



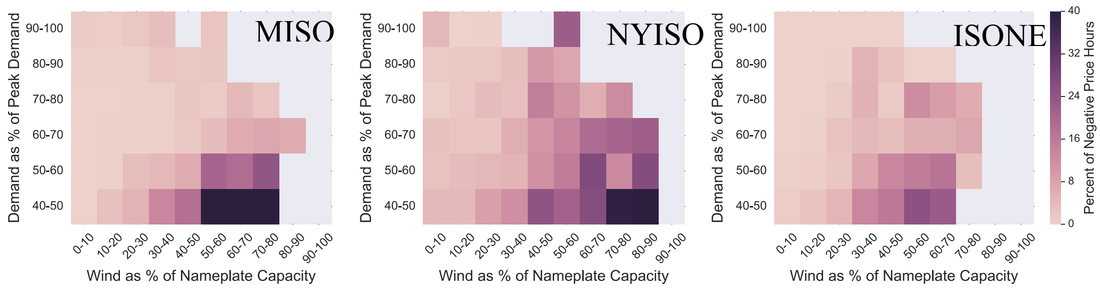
To be clear, wind was not the only resource generating at times of negative prices in SPP (Figure 19). Coal, nuclear, natural gas, and hydropower resources all generated significant amounts of power at times when the energy component of the SPP LMP was negative. Nuclear plants, for example, generated the same amount of power when the price was negative or positive. Coal, gas, and hydropower all decreased generation to some extent during negative price events, though they still operated at well above zero output. These generators may be generating during negative price periods for several reasons. First, as described in Section 2.4, many participants may not be responsive to spot prices and may be self-committing or self-dispatching generation. Second, responsive resources may be ramp constrained such that there is not enough short-term ramp available to address the negative prices. Third, resources may be sitting at minimum in order to ramp up to meet higher expected loads or to provide more ramp later in the day. In contrast to resources that reduced output during periods of negative prices, wind generated relatively more during times of negative prices than during times of positive prices. Similar patterns of higher wind generation during times of negative prices were observed in ERCOT (Appendix G), illustrating the contribution of wind to these events.

Figure 19. Average generation levels for different resources in SPP at times when the energy component of the SPP RT LMP was positive or negative.



A similar relationship between wind and the frequency of negative prices is found in the MISO region near Iowa and Southern Minnesota, and in the region between Upstate New York and Northern Maine (Figure 20). In these areas, lower average LMPs and negative prices were associated with times of low load and high wind generation. The relationship between high wind and low load leading to negative prices is very clear in MISO, whereas negative prices in the northern regions of NYISO and ISO-NE often occurred when wind generation was high, even when the load was not at its lowest levels (i.e., negative prices are more evenly distributed along the vertical axis of the figure, indicating less of a relationship with the level of demand). This pattern, along with the localized nature of negative prices shown earlier (Figure 13), suggests that local transmission constraints might have played a significant role in driving negative prices in the northern regions of NYISO and ISO-NE.[40] Analysis of resource-specific generation patterns during times when the energy component of LMPs was negative in each of these regions shows that wind was a small contributor to the overall energy mix, while several other generation types were generating sizable amounts of electricity (see Appendix G).

Figure 20. Relationship between load, wind, and negative prices in the RT market in the Iowa and Southern Minnesota region of MISO (left), Northern New York (center), and the Vermont to Maine region of ISO-NE (right) for 2017.



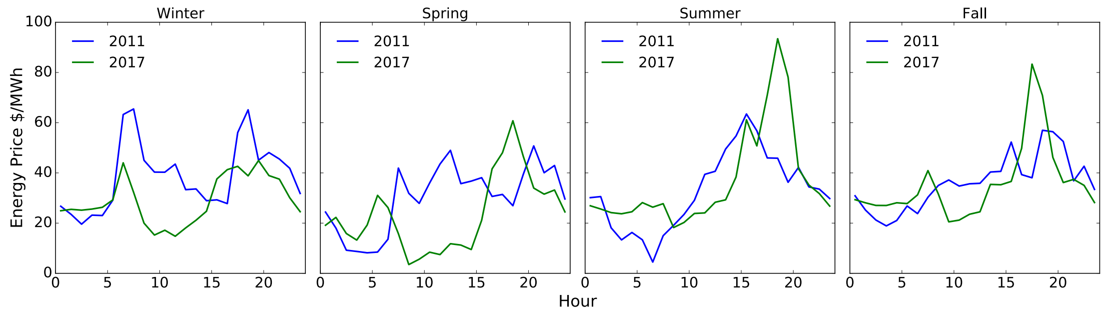
4.3 Impact of solar on real-time wholesale power energy prices in California

The effect of solar on LMPs can best be seen in California. Specifically, increased solar generation in California has shifted the diurnal profile of RT LMPs to be lower in the day and higher in the early evening, particularly in the spring months (Figure 21).

While overall average LMPs did not change significantly between 2011 and 2017, midday prices in the spring were about $30/MWh lower in 2017 than they were for the same hours in 2011. Summer evening LMPs in 2017, in contrast, were $40/MWh greater than in 2011. These higher evening LMPs in the summer of 2017 were due to a small set of very-high-priced hours that occurred when load was greater than peak loads in 2011 and less nuclear plant generation was available than in 2011. Increased renewable and thermal generation contributed to meeting this greater load. The significant ramping needs due to the evening decline in solar output during periods of high demand may have also contributed to these price spikes, though most summer evenings in 2017 contained equally high net-load ramps (but lower load) and did not correspond with similar price spikes. In other seasons, there is evidence of early-evening price spikes due to the increased net-load ramp from declining solar output.

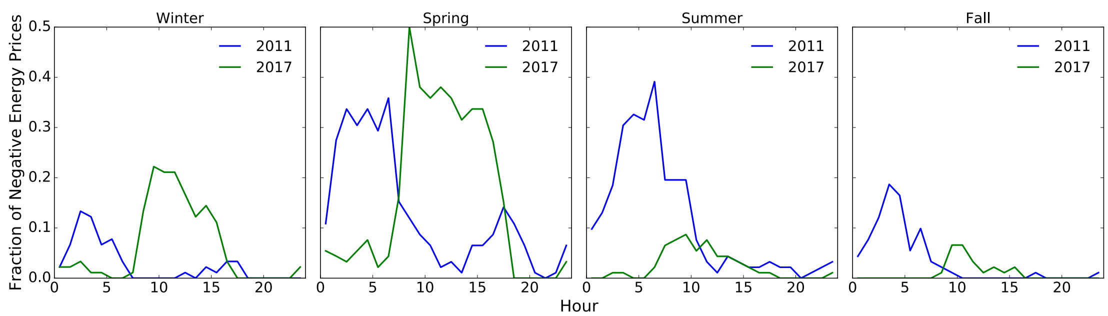
[40] The localized nature of wind impacts on negative prices is further supported by analysis from ISO-NE: "Most of the marginal wind generators in 2017 were located where the transmission system is regularly export-constrained. This means that the wind generators frequently set price within their constrained regions while another resources(s) set price for the rest of the system. Though wind was marginal 19% of the time in 2017, wind was the single marginal fuel type on the system in <1% of all five-minute pricing intervals" (ISO-NE 2018).

Figure 21. Diurnal profile of the energy component of RT LMPs in CAISO for 2011 and 2017.



The decrease in 2017 LMPs during the daytime hours in the spring and winter was due in part to an increase in the frequency of daytime negative prices. The distribution of negative prices over spring and winter days in 2017 clearly follows the pattern of solar generation (Figure 22). In 2011, on the other hand, negative prices were more likely to occur during the night or early morning in spring and summer.

Figure 22. Diurnal profile of negative prices in CAISO for 2011 and 2017.



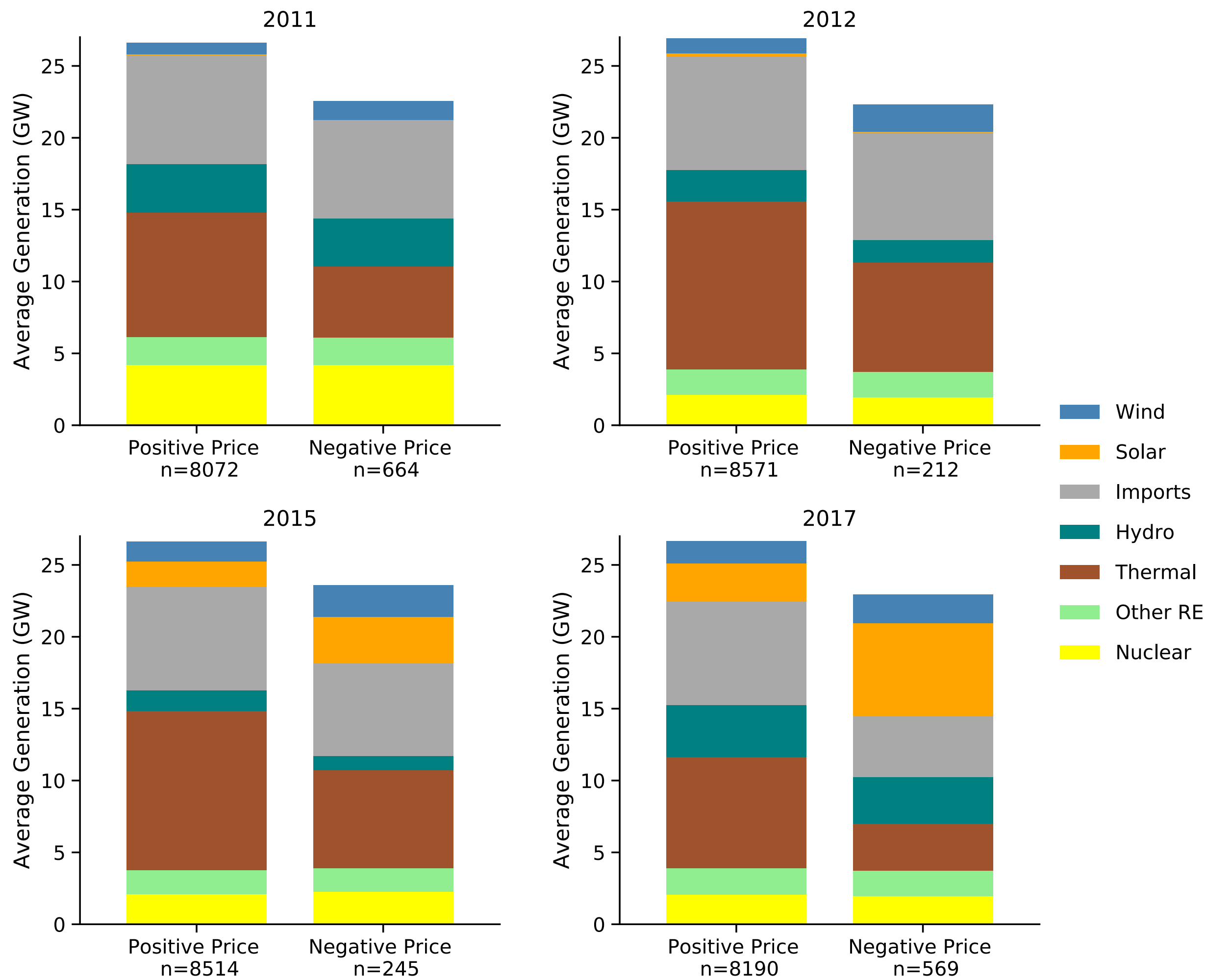
While it is clear that solar was a major contributor to negative prices in 2017, numerous additional factors have changed over the years in the California system leading to increased or decreased incidences of negative prices (Figure 23):

- Hydropower: Hydropower generation was greatest in 2011 and 2017, both years with frequent negative prices. Negative prices were much less frequent in 2015, when hydropower generation was lower. The similar levels in average hydropower generation between positive- and negative-price hours indicate that hydropower had limited flexibility to decrease generation during times of negative prices.
- Nuclear: As with hydropower, constant levels of nuclear generation during positive- and negative-price hours illustrate the limited flexibility of nuclear to reduce output during negative price events. At the start of 2012, the San Onofre nuclear generating station went offline, lowering the contribution of nuclear to negative prices.
- Wind: Wind generation was greater during times of negative prices than during times of positive prices, though overall wind output was small relative to other generating sources.
- Imports: The amount of imports showed little response to negative prices in 2011 and 2012. By 2017, however, the level of imports dropped considerably during negative-price hours. The

growing persistence of negative prices and the introduction of the EIM may have incentivized structural changes allowing for increased flexibility in imports.

- Thermal generation: Thermal generation was lower, though still not close to zero, during negative-price hours. As with imports, the level of thermal generation during negative-price hours was lower in 2017 compared to previous years, suggesting that increased flexibility is being accessed from the thermal fleet over time.
- Load (depicted as the total height of the bars): Negative prices have tended to occur when load was low in all years. The level of the load during negative-price hours remained relatively constant across all of the years, even though the frequency of negative prices varied considerably.

Figure 23. Generation in CAISO during hours when the energy component of the RT LMP was negative in 2011, 2012, 2015, and 2017.



RE = renewable energy

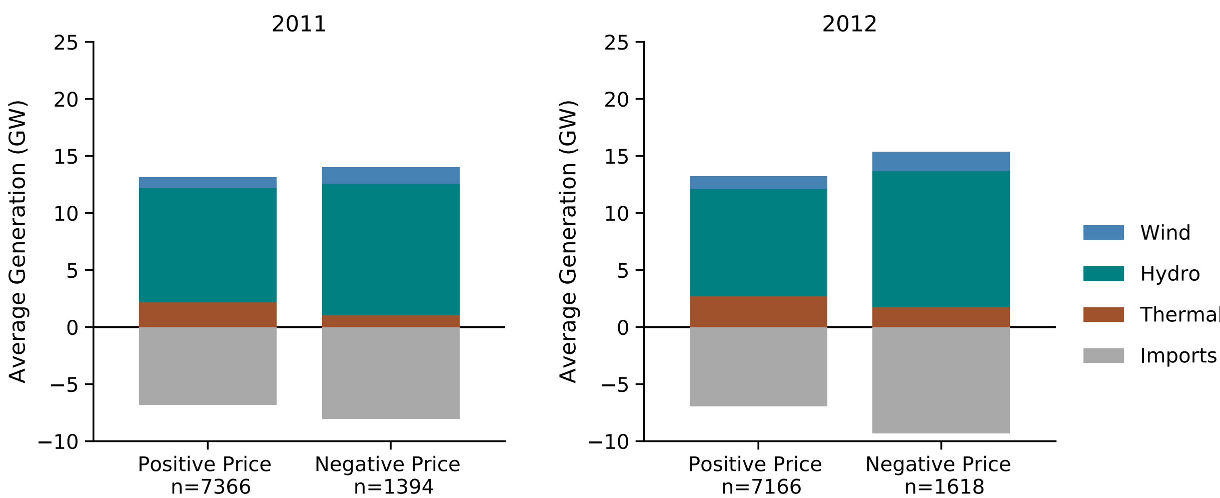
4.4 Hydropower contribution to negative prices in the Pacific Northwest

The preceding discussion showcases that wind and solar contribute to negative wholesale prices but are not the only drivers, because various other types of power plants are also generating at times of negative prices. In 2011/2012, for example, high-hydropower conditions may have been the primary driver of negative wholesale prices in the Pacific Northwest. While hydropower has many positive flexibility attributes, this finding suggests that those attributes have limits.

Earlier, Figure 15a showed that in 2011/2012 negative prices significantly lowered average wholesale power energy prices at pricing nodes associated with hydropower and wind energy. A major contributor to this spike was the increased prevalence of negative prices at nodes with significant hydropower and wind capacity in the Pacific Northwest. Monthly EIA hydropower generation data show that hydropower generation reached peak levels across much of the hydropower-rich West in 2011/2012.

Analysis of data for Bonneville Power Administration (BPA), meanwhile, indicates that hydropower was generating nearly 2.5 GW more during times of negative prices than during positive-price hours in 2012 (Figure 24).[41,42] Wind in BPA was similarly generating more during negative-price hours, but only by a small amount (0.6 GW) compared to hydropower. Because BPA load was also slightly lower during negative-price hours than during positive-price hours, BPA needed to export this extra generation, potentially contributing to region-wide low prices.

Figure 24. Comparison of average generation levels during positive- and negative-price hours at BPA in 2011 and 2012.



Note: Exports from BPA are represented by negative import values

4.5 Transmission expansion and negative prices

As shown earlier in Figure 15, the impact of negative prices falls disproportionately on wind generators relative to coal, gas, and nuclear generation. In some cases, negative prices are localized and can be addressed through expansion of the transmission system to better connect wind resources to loads.

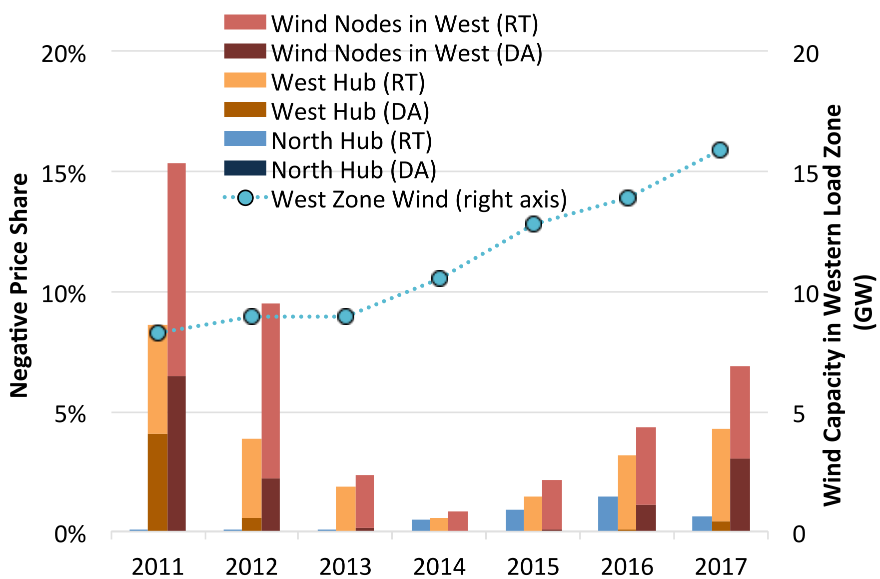
41 Hourly prices are determined through records from a CAISO interface node (SYLMARDC_2_N501) located within BPA. Generation is as reported by BPA.

42 During portions of these years, it was not possible to spill hydropower owing to limits on dissolved nitrogen, for which excess levels can adversely impact fish downstream of dams (EIA 2014).

Naturally, any benefit from the reduced prevalence of negative prices should be weighed against the costs and additional benefits of transmission expansions.

One illustration of the relationship between growth in wind, increased incidences of negative prices, and mitigation through transmission expansion is in the western part of Texas, where major new transmission capacity was constructed between 2011 and 2013 (RS&H 2011; Lasher 2014; Du and Rubin 2018). In 2011, the frequency of negative prices at wind nodes (weighted by the average nearby wind capacity) in West Texas exceeded 15% of all hours in the RT market and 6% of all hours in the DA market. Further east, at a major trading hub near Dallas (the North Hub), negative prices were nonexistent during the same hours (Figure 25).

Figure 25. Frequency of RT and DA negative prices in ERCOT along with expansion of wind capacity.[43]



RT = real-time; DA = day-ahead

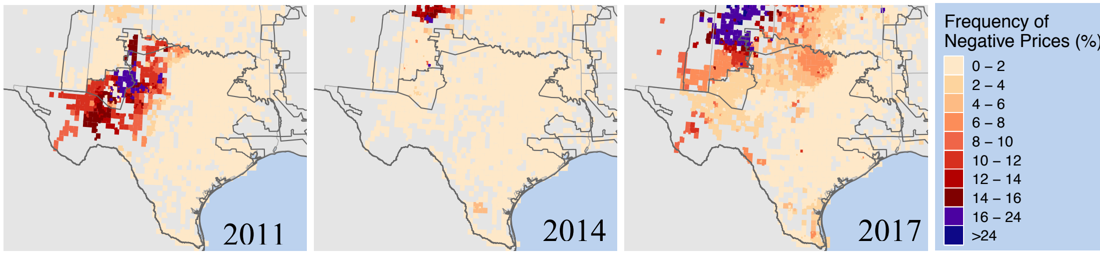
As the CREZ transmission lines came online, negative prices were reduced to below 2% of hours at wind nodes in West Texas by 2014 (

[43] The frequency of DA negative prices is shown in front of the frequency of RT negative prices, rather than being stacked on top of each other.

Figure 26).[44] By 2017, however, wind capacity in West Texas had nearly doubled from its level in 2011, approaching the 18.5-GW wind capacity design level for the CREZ lines. As such, by 2017, negative prices—particularly at wind nodes—were again on the rise. While the expansion of the transmission system between West Texas and the rest of the ERCOT system moderately increased the frequency of negative prices at the North Hub, they have remained below 2% of hours in all years shown.

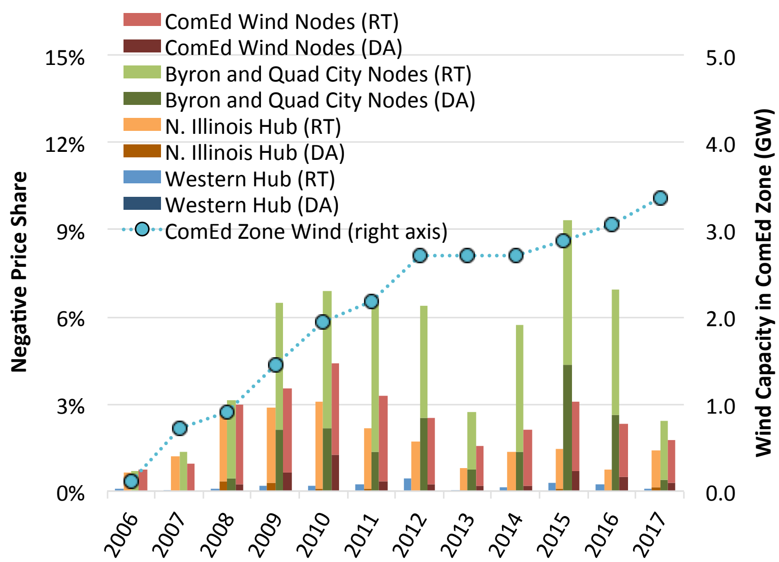
[44] Another more recent example of transmission expansion relieving incidences of negative prices is in the western portion of Oklahoma. The frequent negative prices in 2017 were mitigated by transmission expansion between western and central Oklahoma (Woodward – Tatonga – Matthewson 345-kV project) that came online in February 2018 (SPP 2018b).

Figure 26. Frequency of negative prices in the RT market in 2011 before (left), in 2014 after completion of the CREZ transmission projects (center), and in 2017 as wind growth has continued in ERCOT. State and ERCOT boundary lines are shown.



Another area where transmission expansion has played a role in reducing the frequency of negative prices is in the ComEd zone of PJM in Northern Illinois. This region includes more than 10 GW of nuclear plants and more than 3 GW of wind. Two nuclear plants in the western part of the zone, Byron and Quad Cities, saw an increasing frequency of negative prices in both the RT and DA markets as wind capacity in ComEd grew. The frequency of negative prices reached as high as 9% in the RT market and 4% in the DA market in 2015 (Figure 27).

Figure 27. Frequency of RT and DA negative prices in PJM and wind capacity expansion.[45]

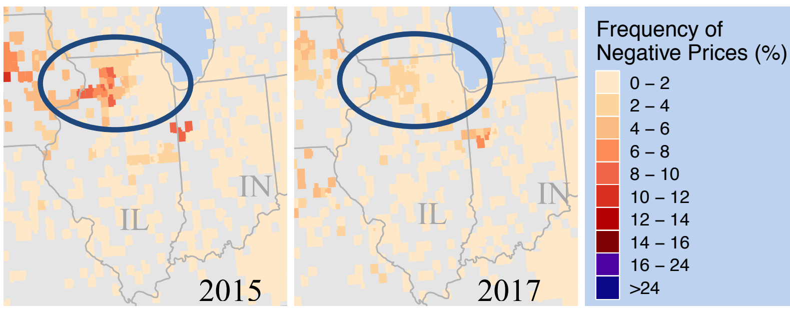


RT = real-time; DA = day-ahead

[45] As with Figure 25, the frequency of DA negative prices is shown in front of the frequency of RT negative prices, rather than being stacked on top of each other.

This effect was highly concentrated at the nuclear nodes, with a lower frequency of negative prices at the wind nodes in ComEd (capacity-weighted average) and at the Northern Illinois Hub. Further to the east, negative prices were consistently less than 0.5% at the Western Hub in Pennsylvania. By 2017, however, the relatively high share of negative prices at the Byron and Quad Cities plants was reduced to a level closer to the level of the wind nodes and the Northern Illinois Hub in the ComEd zone, also shown in Figure 28. A key contributor to this development was the expansion of the PJM transmission network with the 345-kV Byron-Wayne line. This transmission line improved the capacity of the transmission network between the nuclear plants and areas with greater load closer to Chicago (ComEd 2013; Prosack 2017).

Figure 28. Frequency of negative prices in the RT market in Northern Illinois in 2015 before (left) and in 2017 after (right) a transmission project was energized.



5. Conclusions

Centrally organized wholesale power markets in the United States have evolved over time. Some of the more notable recent trends include growth in wind and solar, a steep reduction in the price of natural gas, limited growth in electrical load, and an increase in the retirement of thermal power plants. Building on recent related work (Wiser et al. 2017), this report has assessed the degree to which growth in VRE has influenced wholesale power energy prices in the United States, not in isolation but in comparison to other possible drivers and focused on regions of the country that feature ISOs/RTOs.

Across all U.S. ISO/RTO markets, the dominant driver of the decline in average wholesale prices between 2008 and 2017 was the fall in natural gas prices. Even after the shale-gas boom caused a sustained reduction in natural gas prices, variability of natural gas prices continued to be the largest driver of changes in average wholesale prices—albeit sometimes increasing and sometimes decreasing prices.

The impacts of wind and solar on market-wide average annual wholesale prices were secondary compared to the impacts of natural gas, but they were among the biggest drivers in a second tier of factors that also included expansion and retirement of other generation capacity, changes in demand, generator efficiency, variations in hydropower, and emissions prices. The impact of wind and solar on average wholesale prices increased with their share of total generation. Building on near-term projections from EIA, the impact of additional wind and solar on average wholesale prices will be similar to the impact of thermal generation additions, except in the case of additional solar in California. The projected doubling of solar in California by 2022 is expected to have substantial impacts on average wholesale prices—perhaps foreshadowing larger impacts in other regions on a longer-term basis as solar penetrations grow. Storage and other forms of flexibility could affect these results, but impact of storage on prices was not to captured in the simple supply-curve model.

Beyond the impacts to market-wide average annual prices, VRE has had a more substantial impact on prices in some locations and in altering the temporal patterns of prices. In particular, VRE impacts time-of-day and seasonal pricing patterns, often depressing prices when VRE supply is high but, in some cases, inflating prices at other times.

The analysis demonstrates that the frequency of negative prices is correlated geographically with VRE deployment, and that negative prices in high-VRE regions occur most frequently in those hours with high VRE output. Despite the recent increase in frequency of negative prices, annual average LMPs at most locations have not been heavily impacted by these negative-price hours (i.e., negative prices were mostly small in magnitude). However, some regions have seen significant declines in annual average LMPs owing to negative hourly prices, specifically regions in SPP, regions in CAISO, and northern areas of New York, New Hampshire, and Maine.

Along with the limited regional impacts of negative prices, negative prices reduced the prices near wind, solar, and hydropower generators significantly more than near natural gas, nuclear, and coal generators.

Finally, through a series of in-depth regional analyses, this analysis shows how numerous factors beyond VRE have interacted with VRE to influence local pricing patterns. For example, given the backdrop of expanding VRE, annual changes in hydropower output drove negative pricing events in the Northwest; nuclear retirements, changes in load, and solar expansion led to markedly different diurnal patterns of pricing in California; and the expansion of transmission reduced negative-price hours near wind in Texas and near nuclear in Illinois. The conclusion to draw from all of this is that, while expansion of wind and solar is leading to significant changes in pricing patterns in some regions (by reducing prices, increasing the frequency of negative-price hours, and changing the diurnal patterns of pricing), other factors are also influencing pricing patterns, and attempts to assess the impacts of VRE must carefully consider the full regional context.

A number of important additional areas of research are not covered in this analysis.

- VRE and other factors are likely to impact other grid services priced in wholesale markets, including capacity and ancillary services. Similar to wholesale energy prices, the price of these services varies by region and has changed over time. While the analysis presented in this paper focuses exclusively on energy prices, additional assessments might usefully also address capacity and ancillary service markets, including uplift payments associated with generation that is directed by system operators to operate in ways that differ from their schedule.
- Price changes have differential impacts on the revenue earned by different resources depending on whether the resource operates at a near-constant output irrespective of grid conditions (e.g., nuclear), the resource flexibly responds to changing grid conditions as signaled by changing prices (e.g., combustion turbines), or the resource dispatch is variable and largely driven by weather (e.g., wind and solar). Future research might therefore explore the implications of price changes on the net revenue of different generation assets, depending on their typical dispatch patterns.
- Storage and flexible demand can mitigate some of the price variability associated with growing shares of VRE. While storage was not accounted for in the simple supply-curve model, other approaches are available to integrate storage and other more-complicated features of electricity markets into fundamental models of wholesale prices. Incorporating storage into the analysis appears to be particularly important for assessing near-future wholesale prices in the solar-dominated California market.
- Exploring longer-term power-sector transformation scenarios and related impacts on pricing and market design will require more sophisticated tools than employed in the present paper. Use of such tools can enable a more thorough investigation of future temporal and geographic pricing patterns under a range of future assumptions and conditions. Of particular interest for an investigation with such tools will be the impact of VRE on price volatility and the subsequent impact on revenues of flexible resources.

References

ABB. 2014. "National Offshore Wind Energy Grid Interconnection Study." Cary, North Carolina: ABB, Inc.

Agora. 2015. "The Integration Costs of Wind and Solar Power An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems." Berlin, Germany: Agora Energiewende.

Annan-Phan, Sebastien, and Fabien A. Roques. 2018. "Market Integration and Wind Generation: An Empirical Analysis of the Impact of Wind Generation on Cross-Border Power Prices." *The Energy Journal* 39 (3). www.iaee.org/en/publications/ejarticle.aspx?id=3075.

Bajwa, Maheen, and Joseph Cavicchi. 2017. "Growing Evidence of Increased Frequency of Negative Electricity Prices in U.S. Wholesale Electricity Markets." *IAEE Energy Forum*, 2017.

Balash, Peter, Ken Kern, John Brewer, Justin Adder, Christopher Nichols, Gavin Pickenpaugh, and Erik Shuster. 2018. "Reliability, Resilience and the Oncoming Wave of Retiring Baseload Units." National Energy Technology Laboratory.

Barbose, Galen, and Naim Darghouth. 2018. "Tracking the Sun: Installed Price Trends for Distributed Photovoltaic Systems in the United States - 2018 Edition." Berkeley, CA: Lawrence Berkeley National Laboratory.

Benhmad, François, and Jacques Percebois. 2018. "Photovoltaic and Wind Power Feed-in Impact on Electricity Prices: The Case of Germany." *Energy Policy* 119 (August): 317–26.

Birk, Michael, and Richard Tabors. 2017. "The Impact of Distributed Energy Resources on the Bulk Power System: A Deeper Dive." In *Proceedings of the 50th Hawaii International Conference on System Sciences*.

Bistline, John E. 2017. "Economic and Technical Challenges of Flexible Operations under Large-Scale Variable Renewable Deployment." *Energy Economics* 64 (May): 363–72. https://doi.org/10.1016/j.eneco.2017.04.012.

Bloom, Aaron, Aaron Townsend, David Palchak, Joshua Novacheck, Jack King, Clayton Barrows, Gary Jordan, Billy Roberts, Caroline Draxl, and Kenny Gruchalla. 2016. "Eastern Renewable Generation Integration Study." Golden, CO: National Renewable Energy Laboratory.

BNEF. 2018. "1H 2018 U.S. Renewable Energy Market Outlook." Bloomberg New Energy Finance.

Bolinger, Mark, and Joachim Seel. 2018. "Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition." Berkeley, CA: Lawrence Berkeley National Laboratory.

Brancucci Martinez-Anido, Carlo, Greg Brinkman, and Bri-Mathias Hodge. 2016. "The Impact of Wind Power on Electricity Prices." *Renewable Energy* 94 (August): 474–87. https://doi.org/10.1016/j.renene.2016.03.053.

Brouwer, Anne Sjoerd, Machteld van den Broek, William Zappa, Wim C. Turkenburg, and André Faaij. 2016. "Least-Cost Options for Integrating Intermittent Renewables in Low-Carbon Power Systems." *Applied Energy* 161 (January): 48–74. doi.org/10.1016/j.apenergy.2015.09.090.

Bublitz, Andreas, Dogan Keles, and Wolf Fichtner. 2017. "An Analysis of the Decline of Electricity Spot Prices in Europe: Who Is to Blame?" *Energy Policy* 107 (August): 323–36. doi.org/10.1016/j.enpol.2017.04.034.

Bushnell, James. 2010. "Building Blocks: Investment in Renewable and Non-Renewable Technologies." In *Harnessing Renewable Energy in Electric Power Systems: Theory, Practice, Policy*. Washington D.C.: RFF Press.

Bushnell, James, and Kevin Novan. 2018. "Setting with the Sun: The Impacts of Renewable Energy on Wholesale Power Markets." WP 292. Berkeley, CA: Energy Institute at Haas.

CAISO. 2015. "Q2 2015 Report on Market Issues and Performance." California Independent

System Operator. www.caiso.com/Documents/2015_SecondQuarterReport-MarketIssues_Performance-August2015.pdf.
———. 2017. "2016 Annual Report on Market Issues and Performance." Folsom, CA: California Independent System Operator.
———. 2018. "2017 Annual Report on Market Issues and Performance." Folsom, CA: California Independent System Operator. www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=2ahUKEwip4JOk04neAhWDGXwKHdcdCHkQFjAAegQICRAC&url=http%3A%2F%2Fwww.caiso.com%2FDocuments%2F2017AnnualReportonMarketIssuesandPerformance.pdf&usg=AOvVaw2iUYBHxbcv9zCzJpoR_-2v.
CEC. 2018. "Revised 2017 IEPR GHG Price Projections." California Energy Commission. efiling.energy.ca.gov/GetDocument.aspx?tn=222145.
Chang, Judy W., Mariko Geronimo Aydin, Johannes Pfeifenberger, Kathleen Spees, and John Imon Pedtke. 2017. "Advancing Past 'Baseload' to a Flexible Grid: How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix." The Brattle Group.
Chao, Hung-po. 2011. "Efficient Pricing and Investment in Electricity Markets with Intermittent Resources." *Special Section: Renewable Energy Policy and Development* 39 (7): 3945–53. doi.org/10.1016/j.enpol.2011.01.010.
Clò, Stefano, Alessandra Cataldi, and Pietro Zoppoli. 2015. "The Merit-Order Effect in the Italian Power Market: The Impact of Solar and Wind Generation on National Wholesale Electricity Prices." *Energy Policy* 77 (February): 79–88. doi.org/10.1016/j.enpol.2014.11.038.
Clò, Stefano, and Gaetano D'Adamo. 2015. "The Dark Side of the Sun: How Solar Power Production Affects the Market Value of Solar and Gas Sources." *Energy Economics* 49 (May): 523–30. doi.org/10.1016/j.eneco.2015.03.025.
Cludius, Johanna, Hauke Hermann, Felix Chr. Matthes, and Verena Graichen. 2014. "The Merit Order Effect of Wind and Photovoltaic Electricity Generation in Germany 2008-2016 Estimation and Distributional Implications." *Energy Economics* 44: 302–13. doi.org/10.1016/j.eneco.2014.04.020.
Cochran, J., M. Miller, O. Zinaman, M. Milligan, D. Arent, B. Palmintier, M. O'Malley, et al. 2014. "Flexibility in 21st Century Power Systems." Golden, CO: National Renewable Energy Laboratory.
Cohen, Benjamin. 2018. "2018 CARIS CO2 Forecast." New York Independent System Operator. www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2018-08-22/CARIS2018_CO2Forecast.pdf.
ComEd. 2013. "Direct Testimony on Behalf of Commonwealth Edison Company (13-0657)." Illinois Commerce Commission. www.icc.illinois.gov/docket/files.aspx?no=13-0657&docId=206355.
Craig, Michael T., Paulina Jaramillo, Bri-Mathias Hodge, Nathaniel J. Williams, and Edson Severnini. 2018. "A Retrospective Analysis of the Market Price Response to Distributed Photovoltaic doi.org/10.1016/j.enpol.2018.05.061.
Cutler, Nicholas J., Nicholas D. Boerema, Iain F. MacGill, and Hugh R. Outhred. 2011. "High Penetration Wind Generation Impacts on Spot Prices in the Australian National Electricity Market." *Energy Policy* 39 (10): 5939–49. doi.org/10.1016/j.enpol.2011.06.053.
Davis, Lucas. 2017. "Is Solar Really the Reason for Negative Electricity Prices?" *Energy Institute Blog* (blog). 2017.
De Jonghe, Cedric, Erik Delarue, Ronnie Belmans, and William D'haeseleer. 2011. "Determining Optimal Electricity Technology Mix with High Level of Wind Power Penetration." *Applied Energy* 88 (6): 2231–38. doi.org/10.1016/j.apenergy.2010.12.046.
Deetjen, Thomas A., Jared B. Garrison, Joshua D. Rhodes, and Michael E. Webber. 2016. "Solar PV

Integration Cost Variation Due to Array Orientation and Geographic Location in the Electric Reliability Council of Texas." *Applied Energy* 180 (October): 607–16. doi.org/10.1016/j.apenergy.2016.08.012.
Denholm, Paul, Greg Brinkman, and Trieu Mai. 2018. "How Low Can You Go? The Importance of Quantifying Minimum Generation Levels for Renewable Integration." *Energy Policy* 115 (April): 249–57. doi.org/10.1016/j.enpol.2018.01.023.
Denholm, Paul, Kara Clark, and Matthew O'Connell. 2016. "Emerging Issues and Challenges in Integrating High Levels of Solar into the Electrical Generation and Transmission System." Golden, CO: National Renewable Energy Laboratory.
Denholm, Paul, Josh Eichman, and Robert Margolis. 2017. "Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants." Golden, CO: National Renewable Energy Laboratory.
Denholm, Paul, and Robert Margolis. 2016. "Energy Storage Requirements for Achieving 50% Solar Photovoltaic Energy Penetration in California." Golden, CO: National Renewable Energy Laboratory.
Denholm, Paul, Joshua Novacheck, Jennie Jorgenson, and Matthew O'Connell. 2016. "Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies." Golden, CO: National Renewable Energy Laboratory.
Denholm, Paul, Matthew O'Connell, Greg Brinkman, and Jennie Jorgenson. 2015. "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart." Golden, CO: National Renewable Energy Laboratory.
Di Cosmo, Valeria, and Laura Malaguzzi Valeri. 2014. "The Incentive to Invest in Thermal Plants in the Presence of Wind Generation." *Energy Economics* 43 (May): 306–15. doi.org/10.1016/j.eneco.2014.03.009.
DOE. 2012. "SunShot Vision Study." Washington D.C.: U.S. Department of Energy.
———. 2015. "Wind Vision: A New Era for Wind Power in the United States." Washington D.C.: U.S. Department of Energy.
———. 2017. "Staff Report to the Secretary on Electricity Markets and Reliability." Washington D.C.: U.S. Department of Energy.
———. 2018. "2016 Renewable Energy Grid Integration Data Book." Washington D.C.: U. S. Department of Energy.
Du, Xiaodong, and Ofir D Rubin. 2018. "Transition and Integration of the ERCOT Market with the Competitive Renewable Energy Zones Project." *The Energy Journal* 39 (4): 235–60.
Ederer, Nikolaus. 2015. "The Market Value and Impact of Offshore Wind on the Electricity Spot Market: Evidence from Germany." *Applied Energy* 154 (September): 805–14. doi.org/10.1016/j.apenergy.2015.05.033.
EIA. 2014. "Fewer Wind Curtailments and Negative Power Prices Seen in Texas after Major Grid Expansion." Washington D.C.: Energy Information Administration.
———. 2018a. "Almost All Power Plants That Retired in the Past Decade Were Powered by Fossil Fuels." Washington D.C.: Today in Energy. Energy Information Administration.
———. 2018b. "Annual Energy Outlook 2018." Washington D.C., USA: U.S. Energy Information Administration.
Ela, E., M. Milligan, A. Bloom, A. Botterud, A. Townsend, T. Levin, and B. A. Frew. 2016. "Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Incentivizing Flexibility in System Operations." *The Electricity Journal* 29 (4): 51–60. doi.org/10.1016/j.tej.2016.05.001.
Ela, E., C. Wang, S. Moorty, K. Ragsdale, J. O'Sullivan, M. Rothleder, and B. Hobbs. 2017. "Electricity Markets and Renewables: A Survey of Potential Design Changes and Their Consequences." *IEEE Power and Energy Magazine* 15 (6): 70–82. doi.org/10.1109/MPE.2017.2730827.
EnerNex. 2011. "Eastern Wind Integration and Transmission Study." NREL/SR-5500-47078.

Knoxville, TN: Prepared for the National Renewable Energy Laboratory.
Fagan, Bob, Max Chang, Patrick Knight, Melissa Schultz, Tyler Comings, Ezra Hausman, and Rachel Wilson. 2012. "The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region." Cambridge, MA: Synapse Energy Economics, Inc.
Fagan, Bob, Patrick Lucklow, David White, and Rachel Wilson. 2013. "The Net Benefits of Increased Wind Power in PJM." Cambridge, MA: Synapse Energy Economics, Inc.
Felder, Frank A. 2011. "Examining Electricity Price Suppression Due to Renewable Resources and Other Grid Investments." *The Electricity Journal* 24 (4): 34–46. doi.org/10.1016/j.tej.2011.04.001.
FERC. 2017. "2017 Transmission Metrics: Staff Report." Washington D.C.: Federal Energy Regulatory Commission.
Forsberg, Charles W., Daniel C. Stack, Daniel Curtis, Geoffrey Haratyk, and Nestor Andres Sepulveda. 2017. "Converting Excess Low-Price Electricity into High-Temperature Stored Heat for Industry and High-Value Electricity Production." *The Electricity Journal* 30 (6): 42–52. doi.org/10.1016/j.tej.2017.06.009.
GE Energy. 2005. "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations." Albany, NY: Prepared for NYSERDA.
———. 2010a. "New England Wind Integration Study." Holyoke, MA: ISO New England Inc.
———. 2010b. "Western Wind and Solar Integration Study." Golden, CO: National Renewable Energy Laboratory.
———. 2014. "PJM Renewable Integration Study." Schenectady, NY: Prepared for PJM Interconnection, LLC.
Gifford, Raymond, and Matthew Larson. 2016. "State Actions in Organized Markets: States Strive to 'Fix' Markets and Retain Base Load Generation." Denver, CO: Wilkinson, Baker, Knauer, LLP.
———. 2017. "State Actions in Organized Markets: Continued Use of 'Around Market' Solutions to 'Fix' Markets and the Natural Gas Conundrum." Denver, CO: Wilkinson, Baker, Knauer, LLP.
Gil, H.A., and J. Lin. 2013. "Wind Power and Electricity Prices at the PJM Market." *IEEE Transactions on Power Systems* 28 (4): 3945–53. doi.org/10.1109/TPWRS.2013.2260773.
Gilmore, Joel, Ben Vanderwaal, Ian Rose, and Jenny Riesz. 2014. "Integration of Solar Generation into Electricity Markets: An Australian National Electricity Market Case Study." *IET Renewable Power Generation* 9 (1): 46–56. doi.org/10.1049/iet-rpg.2014.0108.
Goggin, Michael, Rob Gramlich, Steven Shparber, and Alison Silverstein. 2018. "Customer Focused and Clean: Power Markets for the Future." Washington D.C.: Prepared for Wind Solar Alliace. windsolaralliance.org/wp-content/uploads/2018/11/WSA_Market_Reform_report_online.pdf.
Green, Richard J., and Thomas-Olivier Léautier. 2015. "Do Costs Fall Faster than Revenues? Dynamics of Renewables Entry into Electricity Markets." Toulouse School of Economics (TSE).
Haas, Reinhard, Georg Lettner, Hans Auer, and Neven Duic. 2013. "The Looming Revolution: How Photovoltaics Will Change Electricity Markets in Europe Fundamentally." *Energy* 57 (August): 38–43. doi.org/10.1016/j.energy.2013.04.034.
Hale, Elaine T., Brady L. Stoll, and Joshua E. Novacheck. 2018. "Integrating Solar into Florida's Power System: Potential Roles for Flexibility." *Solar Energy* 170 (August): 741–51. doi.org/10.1016/j.solener.2018.05.045.
Haratyk, Geoffrey. 2017. "Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Implications and Policy Options." *Energy Policy* 110 (November): 150–66. doi.org/10.1016/j.enpol.2017.08.023.
Hartner, Michael, André Ortner, Albert Hiesl, and Reinhard Haas. 2015. "East to West – The Optimal Tilt Angle and Orientation of Photovoltaic Panels from an Electricity System

Perspective.” *Applied Energy* 160 (December): 94–107. doi.org/10.1016/j.apenergy.2015.08.097.
Herrero, Ignacio, Pablo Rodilla, and Carlos Batlle. 2018. “Enhancing Intraday Price Signals in U.S. ISO Markets for a Better Integration of Variable Energy Resources.” *The Energy Journal* 39 (3). doi.org/10.5547/01956574.39.3.iher.
Hibbard, Paul, Susan Tierney, and Katherine Franklin. 2017. “Electricity Markets, Reliability and the Evolving U.S. Power System.” Analysis Group. info.aee.net/electricity-markets-reliability-and-the-evolving-us-power-system-report.
Hirth, Lion. 2013. “The Market Value of Variable Renewables: The Effect of Solar Wind Power Variability on Their Relative Price.” *Energy Economics* 38 (July): 218–36. doi.org/10.1016/j.eneco.2013.02.004.
———. 2016. “The Benefits of Flexibility: The Value of Wind Energy with Hydropower.” *Applied Energy* 181 (November): 210–23. doi.org/10.1016/j.apenergy.2016.07.039.
———. 2018. “What Caused the Drop in European Electricity Prices? A Factor Decomposition Analysis.” *The Energy Journal* 39 (1). doi.org/10.5547/01956574.39.1.lhir.
Hirth, Lion, and Simon Müller. 2016. “System-Friendly Wind Power: How Advanced Wind Turbine Design Can Increase the Economic Value of Electricity Generated through Wind Power.” *Energy Economics* 56 (May): 51–63. doi.org/10.1016/j.eneco.2016.02.016.
Hirth, Lion, Falko Ueckerdt, and Ottmar Edenhofer. 2015. “Integration Costs Revisited – An Economic Framework for Wind and Solar Variability.” *Renewable Energy* 74 (February): 925–39. doi.org/10.1016/j.renene.2014.08.065.
Hogan, William W. 2010. “Electricity Wholesale Market Design in a Low-Carbon Future.” In *Harnessing Renewable Energy in Electric Power*, edited by B. Moselle, J. Padilla, and R. Schmalensee. Washington D.C.: RFF Press.
———. 2016. “Virtual Bidding and Electricity Market Design.” *The Electricity Journal* 29 (5): 33–47. doi.org/10.1016/j.tej.2016.05.009.
Hogan, William W., and Susan Pope. 2017. “Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT.” FTI Consulting.
Hummon, Marissa, Paul Denholm, Jennie Jorgenson, David Palchak, Brenden Kirby, and Ookie Ma. 2013. “Fundamental Drivers of the Cost and Price of Operating Reserves.” Golden, CO: National Renewable Energy Laboratory.
IEA. 2011. “Harnessing Variable Renewables: A Guide to the Balancing Challenge.” Paris, France: International Energy Agency.
———. 2016. “Re-Powering Markets: Market Design and Regulation during the Transition to Low-Carbon Power Systems.” Paris, France: International Energy Agency.
ISO-NE. 2016. “2015 Economic Study Evaluation of Offshore Wind Deployment.” ISO New England Inc.
———. 2017. “2016 Economic Study: NEPOOL Scenario Analysis, First Draft.” ISO New England Inc.
———. 2018. “2017 Annual Markets Report.” ISO New England Internal Market Monitor. www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf.
Jenkins, Jesse D. 2017. “What Is Killing Nuclear Power in the American Midwest?” In . Pittsburgh, PA.
Johansson, V., L. Thorson, J. Goop, L. Göransson, M. Odenberger, L. Reichenberg, M. Taljegard, and F. Johnsson. 2017. “Value of Wind Power – Implications from Specific Power.” *Energy* 126 (May): 352–60. doi.org/10.1016/j.energy.2017.03.038.
Kallabis, Thomas, Christian Pape, and Christoph Weber. 2016. “The Plunge in German Electricity Futures Prices – Analysis Using a Parsimonious Fundamental Model.” *Energy Policy* 95 (August): 280–90. doi.org/10.1016/j.enpol.2016.04.025.
Kirschen, Daniel Sadi, and Goran Strbac. 2004. *Fundamentals of Power System Economics*.

Chichester, West Sussex, England ; Hoboken, NJ : John Wiley & Sons, c2004.
Kyritsis, Evangelos, Jonas Andersson, and Apostolos Serletis. 2017. "Electricity Prices, Large-Scale Renewable Integration, and Policy Implications." *Energy Policy* 101 (February): 550–60. doi.org/10.1016/j.enpol.2016.11.014.
Lamont, Alan D. 2008. "Assessing the Long-Term System Value of Intermittent Electric Generation Technologies." *Energy Economics* 30 (3): 1208–31. doi.org/10.1016/j.eneco.2007.02.007.
Lasher, Warren. 2014. "The Competitive Renewable Energy Zones Process." *Quadrennial Energy Task Force*.
LCG. 2016. "Market Effects of Wind Penetration in ERCOT: How Wind Will Change the Future of Energy and Ancillary Service Prices." Los Altos, CA: LCG Consulting.
Levin, Todd, and Audun Botterud. 2015. "Electricity Market Design for Generator Revenue Sufficiency with Increased Variable Generation." *Energy Policy* 87 (December): 392–406. doi.org/10.1016/j.enpol.2015.09.012.
Linn, Joshua, and Kristen McCormack. 2017. "The Roles of Energy Markets and Environmental Regulation in Reducing Coal-Fired Plant Profits and Electricity Sector Emissions." Washington D.C.: Resources for the Future.
Llobet, Gerard, and Jorge Padilla. 2018. "Conventional Power Plants in Liberalized Electricity Markets with Renewable Entry." *The Energy Journal* 39 (3). doi.org/10.5547/01956574.39.3.gllo.
MacCormack, John, Aidan Hollis, Hamidreza Zareipour, and William Rosehart. 2010. "The Large-Scale Integration of Wind Generation: Impacts on Price, Reliability and Dispatchable Conventional Suppliers." *Energy Policy* 38 (7): 3837–46. doi.org/10.1016/j.enpol.2010.03.004.
Maggio, D.J. 2012. "Impacts of Wind-Powered Generation Resource Integration on Prices in the ERCOT Nodal Market." In *2012 IEEE Power and Energy Society General Meeting*, 1–4. doi.org/10.1109/PESGM.2012.6344611.
Makovich, Lawrence, and James Richards. 2017. "Ensuring Resilient and Efficient Electricity Generation: The Value of the Current Diverse US Power Supply Portfolio." IHS Markit.
May, Nils. 2017. "The Impact of Wind Power Support Schemes on Technology Choices." *Energy Economics* 65 (June): 343–54. doi.org/10.1016/j.eneco.2017.05.017.
Milligan, Michael, Bethany A. Frew, Aaron Bloom, Erik Ela, Audun Botterud, Aaron Townsend, and Todd Levin. 2016. "Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Revenue Sufficiency and Long-Term Reliability." *The Electricity Journal* 29 (2): 26–38. doi.org/10.1016/j.tej.2016.02.005.
Mills, Andrew, and Ryan Wiser. 2012. "Changes in the Economic Value of Variable Generation with Increasing Penetration Levels: A Pilot Case Study of California." Berkeley, CA: Lawrence Berkeley National Laboratory.
———. 2013. "Changes in the Economic Value of Photovoltaic Generation at High Penetration Levels: A Pilot Case Study of California." *IEEE Journal of Photovoltaics* 3 (4): 1394–1402. doi.org/10.1109/JPHOTOV.2013.2263984.
———. 2014. "Changes in the Economic Value of Wind Energy and Flexible Resources at Increasing Penetration Levels in the Rocky Mountain Power Area." *Wind Energy* 17 (11): 1711–26. doi.org/10.1002/we.1663.
———. 2015. "Strategies to Mitigate Declines in the Economic Value of Wind and Solar at High Penetration in California." *Applied Energy* 147 (June): 269–78. doi.org/10.1016/j.apenergy.2015.03.014.
Mills, Andrew, Ryan Wiser, and Joachim Seel. 2017. "Power Plant Retirements: Trends and Possible Drivers." Berkeley, CA: Lawrence Berkeley National Laboratory.
MIT. 2015. "The Future of Solar Energy." Massachusetts Institue of Technology.
Monitoring Analytics. 2018. "2017 State of the Market Report for PJM." Eagleville, PA: Monitoring

Analyitcs. www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf.
NESCOE. 2017. "Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study; Phase I: Scenario Analysis." New England States Committee on Electricity.
Newberry, David, David Pollitt, Robert Ritz, and Wadim Strielkowski. 2017. "Market Design for a High-Renewables European Electricity System." University of Cambridge.
NREL. 2012. "Renewable Electricity Futures Study." Golden, CO: National Renewable Energy Laboratory.
NY-ISO. 2010. "Growing Wind: Final Report of the NYISO 2010 Wind Generation Study." Rensselaer, NY: New York Independent System Operator.
Obersteiner, Carlo. 2012. "The Influence of Interconnection Capacity on the Market Value of Wind Power." *Wiley Interdisciplinary Reviews: Energy and Environment* 1 (2): 225–32. doi.org/10.1002/wene.21.
Obersteiner, Carlo, and Marcelo Saguan. 2011. "Parameters Influencing the Market Value of Wind Power – a Model-Based Analysis of the Central European Power Market." *European Transactions on Electrical Power* 21 (6): 1856–68. doi.org/10.1002/etep.430.
Olson, Arne, and Ryan Jones. 2012. "Chasing Grid Parity: Understanding the Dynamic Value of Renewable Energy." *The Electricity Journal* 25 (3): 17–27. doi.org/10.1016/j.tej.2012.03.001.
Orvis, Robbie, and Sonia Aggarwal. 2017. "A Roadmap for Finding Flexibility in Wholesale Markets." San Francisco, CA: Energy Innovation: Policy and Technology LLC.
Perez-Arriaga, Ignacio J., and Carlos Batlle. 2012. "Impacts of Intermittent Renewables on Electricity Generation System Operation." *Economics of Energy & Environmental Policy* 1 (2). doi.org/10.5547/2160-5890.1.2.1.
Potomac Economics. 2017a. "2016 State of the Market Report for the ERCOT Electricity Markets." Fairfax, VA: Potomac Economics, Ltd.
———. 2017b. "2016 State of the Market Report for the MISO Electricity Markets." Fairfax, VA: Potomac Economics, Ltd.
———. 2018a. "2017 State of the Market Report for the ERCOT Electricity Markets." Fairfax, VA: Potomac Economics, Ltd. www.potomaceconomics.com/wp-content/uploads/2018/05/2017-State-of-the-Market-Report.pdf.
———. 2018b. "2017 State of the Market Report For the NYISO Electricity Markets." Potomac Economics, Ltd. www.potomaceconomics.com/wp-content/uploads/2018/06/NYISO-2017-SOM-Report-5-07-2018_final.pdf.
———. 2018c. "2017 State of the Market Report For the ISO New England Electricity Markets." Potomac Economics, Ltd. www.potomaceconomics.com/wp-content/uploads/2018/06/ISO-NE-2017-EMM-SOM-Report_6-17-2018_Final.pdf.
———. 2018d. "2017 State of the Market Report for the MISO Electricity Markets." Fairfax, VA: Potomac Economics, Ltd. www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf.
Prosack, Joseph. 2017. "The New Byron-Wayne Line: ComEd Congestion Implications." *Genscape* (blog). April 12, 2017. www.genscape.com/blog/new-byron-wayne-line-comed-congestion-implications.
Quint, Dov, and Steve Dahlke. 2019. "The Impact of Wind Generation on Wholesale Electricity Market Prices in the Midcontinent Independent System Operator Energy Market: An Empirical Investigation." *Energy* 169 (February): 456–66. doi.org/10.1016/j.energy.2018.12.028.
Reichenberg, Lina, Fredrik Hedenus, Mikael Odenberger, and Filip Johnsson. 2018. "The Marginal System LCOE of Variable Renewables – Evaluating High Penetration Levels of Wind and Solar in Europe." *Energy* 152 (June): 914–24.

https://doi.org/10.1016/j.energy.2018.02.061.
Riva, Alberto Dalla, Janos Hethey, and Aisma Vitina. 2017. "Impacts of Wind Turbine Technology on the System Value of Wind in Europe." Prepared for IEA Wind Task 26.
Robinson, Dennis. 2014. "Negative LMPs: Understanding Negative LMPs since the Implementation of EMOF on ISO-NE." ISO New England. www.iso-ne.com/static-assets/documents/2015/02/a09_iso_presentation_02_10_15.pptx.
RS&H. 2011. "CREZ Progress Report No. 5 (October Update)." Austin, TX: Public Utility Commission of Texas.
Sáenz de Miera, Gonzalo, Pablo del Río González, and Ignacio Vizcaíno. 2008. "Analysing the Impact of Renewable Electricity Support Schemes on Power Prices: The Case of Wind Electricity in Spain." *Energy Policy* 36 (9): 3345–59. doi.org/10.1016/j.enpol.2008.04.022.
Seel, Joachim, Andrew Mills, and Ryan Wiser. 2018. "Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making." Berkeley, CA: Lawrence Berkeley National Laboratory.
Sensfuß, Frank, Mario Ragwitz, and Massimo Genoese. 2008. "The Merit-Order Effect: A Detailed Analysis of the Price Effect of Renewable Electricity Generation on Spot Market Prices in Germany." *Energy Policy* 36 (8): 3086–94.
Shawhan, Daniel L., and Paul D. Picciano. 2019. "Costs and Benefits of Saving Unprofitable Generators: A Simulation Case Study for US Coal and Nuclear Power Plants." *Energy Policy* 124 (January): 383–400. doi.org/10.1016/j.enpol.2018.07.040.
Sivaram, Varun, and Shayle Kann. 2016. "Solar Power Needs a More Ambitious Cost Target." *Nature Energy* 1 (4): 16036. doi.org/10.1038/nenergy.2016.36.
Spees, Kathleen, Johannes Pfeifenberger, Samuel Newell, and Judy Chang. 2018. "Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively." Boston, MA: The Brattle Group.
SPP. 2017. "State of the Market 2016." Little Rock, AR: Southwest Power Pool.
———. 2018a. "State of the Market 2017." Little Rock, AR: Southwest Power Pool. www.spp.org/Documents/57928/SPP_MMU_ASOM_2017.pdf.
———. 2018b. "State of the Market Spring 2018." Little Rock, AR: Southwest Power Pool. www.spp.org/documents/58275/spp_mmu_quarterly_spring_2018.pdf.
Steggals, Will, Robert Gross, and Philip Heptonstall. 2011. "Winds of Change: How High Wind Penetrations Will Affect Investment Incentives in the GB Electricity Sector." *Energy Policy* 39 (3): 1389–96. doi.org/10.1016/j.enpol.2010.12.011.
Tabors, Richard, Lorna Omondi, Aleksandr Rudkevich, Evgeniy Goldis, and Kofi Amoako-Gyan. 2015. "Price Suppression and Emissions Reductions with Offshore Wind: An Analysis of the Impact of Increased Capacity in New England." In *HICSS '15 Proceedings of the 2015 48th Hawaii International Conference on System Sciences*.
Tabors, Richard, Aleksandr Rudkevich, and J. Richard Hornby. 2014. "Rate Impact on LIPA Resident and Commercial Customers Of 250MW Offshore Wind Development on Eastern Long Island." Prepared for the Long Island Power Authority.
Traber, Thure, and Claudia Kemfert. 2011. "Gone with the Wind? — Electricity Market Prices and Incentives to Invest in Thermal Power Plants under Increasing Wind Energy Supply." *Energy Economics* 33 (2): 249–56. doi.org/10.1016/j.eneco.2010.07.002.
Tsai, Chen-Hao, and Derya Eryilmaz. 2018. "Effect of Wind Generation on ERCOT Nodal Prices." *Energy Economics* 76 (October): 21–33. doi.org/10.1016/j.eneco.2018.09.021.
Tveten, Åsa Grytli, Jon Gustav Kirkerud, and Torjus Folsland Bolkesjø. 2016. "Integrating Variable Renewables: The Benefits of Interconnecting Thermal and Hydropower Regions." *International Journal of Energy Sector Management* 10 (3): 474–506. doi.org/10.1108/IJESM-08-2014-0006.

Welisch, Marijke, André Ortner, and Gustav Resch. 2016. "Assessment of RES Technology Market Values and the Merit-Order Effect – an Econometric Multi-Country Analysis." *Energy & Environment* 27 (1): 105–21. doi.org/10.1177/0958305X16638574.

Winkler, Jenny, Martin Pudlik, Mario Ragwitz, and Benjamin Pfluger. 2016. "The Market Value of Renewable Electricity – Which Factors Really Matter?" *Applied Energy* 184 (December): 464–81. doi.org/10.1016/j.apenergy.2016.09.112.

Wiser, R. H., A. D. Mills, J. Seel, T. Levin, and A. Botterud. 2017. "Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs." LBNL-2001082. Berkeley, CA: Lawrence Berkeley National Laboratory. escholarship.org/uc/item/4d01m8vt.

Wiser, Ryan, Galen Barbose, Jenny Heeter, Trieu Mai, Lori Bird, Mark Bolinger, Alberta Carpenter, et al. 2016. "A Retrospective Analysis of the Benefits and Impacts of US Renewable Portfolio Standards." Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory.

Wiser, Ryan, and Mark Bolinger. 2018. "2017 Wind Technologies Market Report." Washington D.C.: U. S. Department of Energy.

Wiser, Ryan, Andrew Mills, Joachim Seel, Todd Levin, and Audun Botterud. 2017. "Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs." Berkeley, CA: Lawrence Berkeley National Laboratory.

Woo, C. K., T. Ho, J. Zarnikau, A. Olson, R. Jones, M. Chait, I. Horowitz, and J. Wang. 2014. "Electricity-Market Price and Nuclear Power Plant Shutdown: Evidence from California." *Energy Policy* 73 (October): 234–44. doi.org/10.1016/j.enpol.2014.05.027.

Woo, C. K., I. Horowitz, J. Moore, and A. Pacheco. 2011. "The Impact of Wind Generation on the Electricity Spot-Market Price Level and Variance: The Texas Experience." *Energy Policy* 39 (7): 3939–44. doi.org/10.1016/j.enpol.2011.03.084.

Woo, C. K., Ira Horowitz, Jay Zarnikau, Jack Moore, Brendan Schneiderman, Tony Ho, and Eric Leung. 2016. "What Moves the Ex Post Variable Profit of Natural-Gas-Fired Generation in California?" *The Energy Journal* 37 (3). doi.org/10.5547/01956574.37.3.cwoo.

Woo, C. K., J. Moore, B. Schneiderman, T. Ho, A. Olson, L. Alagappan, K. Chawla, N. Toyama, and J. Zarnikau. 2016. "Merit-Order Effects of Renewable Energy and Price Divergence in California's Day-Ahead and Real-Time Electricity Markets." *Energy Policy* 92 (May): 299–312. doi.org/10.1016/j.enpol.2016.02.023.

Woo, C. K., J. Zarnikau, J. Kadish, I. Horowitz, Jianhui Wang, and A. Olson. 2013. "The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest." *IEEE Transactions on Power Systems* 28 (4): 4245–53. doi.org/10.1109/TPWRS.2013.2265238.

Würzburg, Klaas, Xavier Labandeira, and Pedro Linares. 2013. "Renewable Generation and Electricity Prices: Taking Stock and New Evidence for Germany and Austria." *Energy Economics* 40, Supplement 1: S159–71. doi.org/10.1016/j.eneco.2013.09.011.

Appendix A: Detailed Description of Simple Supply-Curve Model of Wholesale Power Energy Prices

A relatively simple supply-curve model is used to estimate hourly market-clearing prices for electricity in each region based on finding the intersection of the demand and supply curves. This hourly price is then averaged over the year to estimate the annual average reported in the analysis. For simplicity, certain resources that vary with time (e.g., VRE, imports, and hydropower) are netted from the demand curve (using the resulting net demand) and the supply curve includes only thermal resources. This only affects the way the analysis is conducted, not the result (i.e., subtracting a variable resource from the demand curve has the same effect on the price as adding the resource to the supply curve).

The supply curve is based on a simple merit order of generation from lowest marginal cost to highest marginal cost. The estimated marginal cost of each plant is based on the heat rate of the unit, the fuel cost, the emissions rate of the unit, the emissions price, and other variable operations and maintenance costs. Natural gas fuel costs vary on a daily basis following the trading price at major natural gas trading hubs. Coal fuel costs vary on a monthly basis following average coal production costs in each plant's state as reported by EIA. The capacity of each generator is based on its summer or winter capacity, depending on the season, de-rated by a seasonal availability factor. The summer capacity is de-rated using only the forced outage rate, whereas the winter capacity is de-rated by both the forced outage rate and the scheduled outage rate. By applying the scheduled outage rate to the winter capacity, the model, in effect, assumes that scheduled maintenance occurs only in the winter. Outage rates are technology specific (rather than unit specific). With two exceptions, this simple supply curve ignores numerous real constraints, including unit-specific minimum-generation levels, startup times, ramp rates, transmission limits, heat rate variation based on loading, etc. The first exception is that nuclear plants are assumed to always be at full capacity (accounting for de-rates) and that combined-heat-and-power units are assumed to not drop below 35% of their capacity (Denholm, Brinkman, and Mai 2018). The second exception is that a transmission constraint is included between PJM East and PJM West (additional details below), because modeling PJM as a single market consistently deviated from actual historical prices.

Despite the many simplifications, the supply-curve approach does a reasonably good job of estimating annual average wholesale prices for all markets, with the largest errors occurring in SPP. The remainder of this appendix provides greater detail on the key assumptions and data sources used in modeling wholesale electricity prices; additional details are available from the authors.

Demand

Hourly 2008–2017 load profiles, net of distributed photovoltaics (DPV), for each market were taken directly from ABB's Velocity Suite database. For CAISO, ERCOT, PJM East, NYISO, and ISO-NE, these demand profiles were used directly. For other regions, the historical demand does not match with the current generation assigned to that market in ABB Velocity Suite, because the market footprint changed over the historical period considered. In these cases, the ISO/RTO-reported demand was scaled-up in earlier years to match the more recent ratio of EIA-reported sales in states currently covered by the ISO/RTO to the ISO/RTO-reported demand. Demand in 2008 for SPP was scaled based on sales in Oklahoma, Kansas, Nebraska, South Dakota, North Dakota, and Missouri. Demand in 2008 and 2012 for MISO was scaled based on sales in Louisiana, Arkansas, Illinois, Indiana, Michigan, Iowa, Wisconsin, Minnesota, and North Dakota. Demand in 2008 and 2012 in PJM West was scaled based on sales in Illinois, Michigan, Kentucky, Ohio, and West Virginia. The result is that each ISO/RTO is effectively modeled based on its 2017 footprint, even in earlier years.[46]

Demand was then calculated by adding DPV profiles, described below, to the demand net of DPV. To project demand profiles to 2022, 2017 demand shapes from each ISO/RTO were increased by an ISO/RTO-specific growth rate. The growth rate was calculated using the EIA 2018 *Annual Energy Outlook* (AEO) projection of each ISO/RTO region's demand growth between 2017 and 2022.

Wind

Hourly 2008–2017 wind data for MISO, SPP, ERCOT, and PJM were taken directly from ABB's Velocity Suite database. ABB did not have data from 2008 for CAISO nor for 2008 and 2012 for ISO-NE and NYISO. Aggregate wind profiles for 2012 for ISO-NE and NYISO were provided directly by the respective ISO/RTO.[47] Wind output in 2008 was estimated using a regression analysis that took actual wind data from 2011–2012 and regressed it against modeled wind data (and other weather data) from the National Renewable Energy Laboratory's (NREL's) Wind Integration National Dataset Toolkit from 2011–2012. The resulting regression model was used to predict actual ISO/RTO-specific 2008 wind output for ISO-NE, NYISO, and CAISO. The regression model used a non-parametric regression technique that pruned non-explanatory covariates to reduce overfitting concerns.

To project wind profiles to 2022, 2017 wind shapes from each ISO/RTO were increased by an ISO/RTO-specific growth rate. The growth rate was calculated using EIA AEO 2018's projection of each region's wind energy growth between 2017 and 2022.

[46] As discussed below, wind, solar, hydropower, and imports were not adjusted based on the changing footprint of the ISO/RTO. Instead the hourly data directly from the ISO/RTO was used. For VRE-related results, this is a minor issue for the three affected regions (SPP, MISO, and PJM West), because VRE penetrations in 2008 were much lower than in 2017, irrespective of the footprint. Assignment of thermal generation to an ISO/RTO, on the other hand, was kept consistent with the 2017 footprint in all years.

[47] ISO-NE wind data from www.iso-ne.com and NYISO wind data from personal communication with Arvind Jaggi.

Wind Penetration

Market	2008	2012	2017	2022
CAISO	1.1%	2.8%	4.5%	8.6%
ERCOT	4.9%	9.2%	17.4%	20.3%
SPP	2.6%	7.5%	25.3%	39.5%
MISO	1.3%	4.7%	7.7%	11.6%
PJM	0.4%	1.6%	2.7%	3.3%
NYISO	0.7%	1.7%	2.7%	3.8%
ISO-NE	0.1%	0.9%	2.8%	3.1%

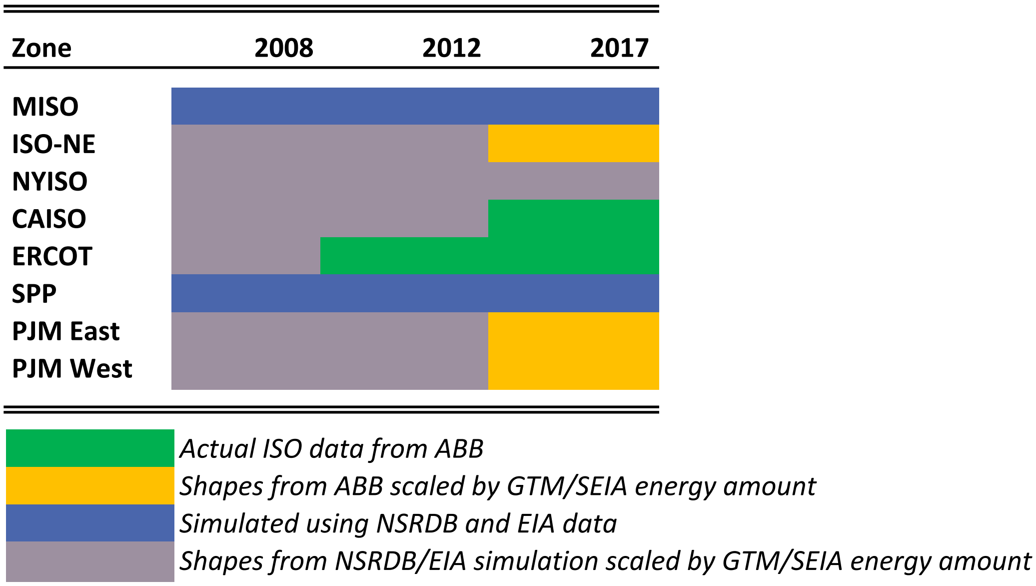
Utility-Scale Photovoltaics

Various data sources were used to build the utility-scale photovoltaics (UPV) profiles. For ERCOT (2012–2017) and CAISO (2017), hourly UPV data were taken directly from ABB's Velocity Suite database. ABB data were also used for solar shapes in PJM (2017) and ISO-NE (2017); however, solar production estimates from Greentech Media (GTM)/Solar Energy Industries Association (SEIA)[48] were used to scale the ABB data, because the ISO/RTO-provided hourly data cover only a fraction of the UPV capacity installed in these regions.

For all other years and ISO/RTO regions, solar shapes were simulated using a combination of NREL's National Solar Radiation Database (NSRDB) and EIA form 860's utility-scale solar installation data. There were four steps to create these shapes: (1) calculate UPV capacity by lat/long coordinate using EIA 860; (2) collect historical solar irradiation data for each lat/long coordinate using the NSRDB (2008–2017); (3) simulate hourly solar capacity factors using the irradiation data and NREL's System Advisor Model (SAM); and (4) weight the capacity factors for each lat/long coordinate by the EIA capacity. This method was employed for each ISO/RTO in this analysis by assigning each lat/long coordinate to a specific ISO/RTO region.

[48] Specifically, GTM/SEIA data were used to estimate state-level solar capacity additions, supplemented by Interstate Renewable Energy Council data for earlier years; see Wiser et al. (2017) for more details.

Source of ISO UPV Data



The hourly solar shapes were scaled to match the total annual solar energy production for a given year and region. For each ISO/RTO region, hourly generation was calculated using installed UPV capacity (2008–2017) by date from ABB's Velocity Suite generator database. The resulting UPV generation output was used directly for every year for MISO and SPP, where a changing ISO/RTO footprint would have made the alternative of scaling the output to state-based estimates of solar less accurate. For the other regions, which had stable ISO/RTO footprints, the UPV generation was scaled using total UPV energy production estimates from GTM/SEIA. The table above summarizes the data sources for the UPV profiles used in this analysis.

To project UPV profiles to 2022, 2017 UPV shapes from each ISO/RTO were increased by an ISO/RTO-specific growth rate. The growth rate was calculated using EIA AEO 2018's projection of each region's UPV energy growth between 2017 and 2022.

Solar Penetration[49]

Market	2008	2012	2017	2022
CAISO	0.5%	1.1%	13.5%	25.8%
ERCOT	0.0%	0.1%	0.7%	2.1%
SPP	0.0%	0.0%	0.2%	0.3%
MISO	0.0%	0.0%	0.2%	0.7%
PJM	0.0%	0.2%	0.9%	1.3%
NYISO	0.0%	0.1%	0.8%	1.7%
ISO-NE	0.0%	0.2%	2.4%	6.0%

[49] Solar penetration in this table reflects both UPV and DPV generation as a percentage of annual energy from demand.

Distributed Photovoltaics

Similar to the majority of UPV profiles, a combination of NREL's NSRDB and estimates of DPV energy production for each ISO/RTO from GTM/SEIA were used to generate DPV profiles. In addition, Lawrence Berkeley National Laboratory's *Tracking the Sun* (TTS) database of non-utility-scale DPV installations was used for those states covered by TTS. There were five steps to create these profiles: (1) calculate DPV capacity by county using the TTS dataset; (2) collect historical solar irradiation data for each county in TTS using the NSRDB (2008–2017); (3) simulate hourly solar capacity factors using the irradiation data and NREL's SAM; (4) weight the capacity factors by county by the TTS country-level capacity within an ISO/RTO region; and (5) scale the hourly capacity factors by the annual DPV energy production estimates. This method was employed for each ISO/RTO in this analysis by assigning each county a specific ISO/RTO region.

To project DPV profiles to 2022, 2017 DPV shapes from each ISO/RTO were increased by an ISO/RTO-specific growth rate. The growth rate was calculated using EIA AEO 2018's projection of each ISO/RTO region's onsite solar energy growth between 2017 and 2022.

Other Renewable Energy Profiles

Other renewable energy profiles (geothermal, biomass, etc.) were included in the net demand calculations for CAISO, where the other renewable energy quantities are a substantial fraction of overall generation, and historical hourly data are available over a long period. Hourly profiles for 2012 and 2017 were taken directly from ABB's Velocity Suite database. For 2008, the hourly profile from 2016 was scaled by the monthly ratio of 2008 to 2016 generation from other renewable energy reported to EIA. In other ISOs/RTOs, the other renewable energy is a much smaller share of total generation, and it was included in the dispatch stack of the supply curve as a thermal generator.

For the future projections, the 2017 profile was used for 2022, holing the other renewable energy constant.

Hydropower

Rather than using static dispatch profiles for hydropower, hydropower was assumed to be dispatched in response to the net demand (demand less wind and solar in this case) and as a function of precipitation. The relationship between hydropower, net demand, and precipitation was developed using regressions over an historical period depending on data availability. Precipitation data were based on a monthly value of the moving average of precipitation measured at a U.S. Geological Survey gauge in each region with a window of 1 year. Hydropower regressions were developed for CAISO, ISO-NE, and NYISO. Hydropower was excluded altogether in all other regions, given its small share of total generation.

The justification for using a historical relationship between net demand and hydropower production, rather than static profiles, is that hydropower production—like thermal plant production—would be different than historically observed if the net demand were different than observed. For example, using a static hydropower profile from 2017 implicitly assumes that hydropower production would not be any different had solar generation decreased to 2008 levels. By dynamically adjusting the hydropower profile, based on historical relationships between hydropower and net demand, the responsiveness of hydropower to grid conditions is better captured by the model.

For the future projections, the 2017 precipitation was used for 2022, holding the precipitation constant.

Imports

Similar to hydropower, imports were allowed to vary with the hourly net demand rather than using static profiles. Imports are based on a regression of net demand, the square of net demand, and monthly imports estimated from EIA. For most regions, the hourly import data used in the regression are based on the total net actual interchange from EIA's U.S. Electric System Operating Data (using data from 2016–2017). For CAISO and PJM, longer histories of hourly import profiles provided by ABB were used. In the case of MISO, the amount of imports from the regressions differed from annual average imports reported by the MISO market monitor. These differences were large enough to adversely affect the average wholesale prices from the model. In this case, the imports from the regression were scaled by the historical annual average reported by the market monitor.

For the future projections, the 2017 monthly net imports were used for 2022, holding the net imports constant.

Thermal Generators

Data for thermal generators were primarily obtained directly from the ABB Velocity Suite database, including the ISO/RTO where the generator operates, summer and winter capacity, forced outage rate, scheduled outage rate, whether or not the generator is a combined-heat-and-power unit, and variable operations and maintenance costs. The heat rate and emissions rate for each unit are based on U.S. Environmental Protection Agency continuous emission monitoring system (CEMS) data similarly accessed through ABB Velocity Suite. Unit-specific heat rates and emissions rates for each month of 2008, 2012, and 2017 were based on the CEMS data. Where data were not directly available for a particular month or year, averages for similar plants in the same market region were used.

For the projections of generator capacity to 2022, a regional rate of additions or retirements from EIA AEO 2018's projection of each region's rate between 2017 and 2022 were used to adjust coal, oil and natural gas steam, combined cycle, combustion turbine/diesel, and nuclear generation capacity. Existing generators with the earliest planned retirement dates were selected for retirement up to the level of retirement projected by EIA (continuing with selecting the oldest generators if more needed to be retired). New generation capacity that was added was assumed to have characteristics similar to the most recently built generation of the same type in each ISO/RTO.

Fuel Costs

Daily natural gas prices from major trading hubs in each region were obtained from ABB's Velocity Suite. Hubs were selected largely based on guidance from market monitoring reports for each ISO/RTO.

Natural Gas Price Hubs

Market	Years	Name
CAISO	2008	SoCal Border
CAISO	2012-2017	SoCal Citygate
ERCOT	2008-2017	Houston Ship Channel
SPP	2008-2017	Panhandle
MISO	2008-2017	Chicago Citygate
PJM West	2008-2017	Average of Dominion North Point, Columbia Appalachia, and Chicago Citygate
PJM East	2008-2017	Average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5
NYISO	2008-2012	Average of Iroquois Zone 2 and TETCO 3
NYISO	2017	Average of Iroquois Zone 2 and the Millenium Hub
ISO-NE	2008-2017	Algonquin Citygates

Monthly coal fuel costs were calculated as the average coal production cost in each state and month as reported to EIA. The production cost data were accessed through ABB's Velocity Suite.

Annual fuel costs for other fuels (petroleum, uranium, renewable, etc.) were calculated as the average fuel costs in each region for each fuel as reported to EIA and accessed through ABB Velocity Suite.

Fuel costs to 2022, were calculated based on a percent fuel cost change between 2017 and 2022 for each ISO/RTO using EIA AEO 2018. Future coal, natural gas, and petroleum fuel costs were available through the EIA AEO. This percent cost change was then applied to the 2017 price data for each ISO/RTO region. Other fuel costs were assumed to not change from 2017 to 2022.

Emissions Prices

The effects of emissions prices for NO_x, SO_2, and CO_2 in each region depended on whether a majority of plants in the specific ISO/RTO region faced those costs. Data determining whether a generator was impacted by an emissions price were taken from ABB's Velocity Suite generator database. NO_x and SO_2 emissions prices were taken from SNL Financial from 2008–2017. California carbon prices were taken from the Climate Policy Initiative, and RGGI prices were taken from SNL (2014–2017) and from EIA (2008–2014).[50]

Projections of CO_2 prices to 2022, relied on California Energy Commission projections for California's cap-and-trade program and NYISO projections for RGGI carbon prices. NO_x and SO_2 prices were held constant between 2017 and 2022.

Negative Bids

As described above, when the net load exceeds the minimum generation level, prices are assumed to fall to the level of negative bids. The assumed negative bids varied across regions based on the observed average negative price across nodes in each market for 2017.

[50] California dashboard: http://calcarbondash.org/ and EIA RGGI price: https://www.eia.gov/todayinenergy/detail.php?id=31432.

Negative Bids

Market	$/MWh
CAISO	-$9.9
ERCOT	-$2.6
SPP	-$9.6
MISO	-$11.7
PJM	-$10.2
NYISO	-$10.5
ISO-NE	-$17.1

PJM Split

In PJM, a transmission constraint was included to more accurately represent the flow of energy between PJM West and PJM East during constrained hours. The 5,000-MW transfer capability between the regions was based on PJM's transfer limits and flows database.[51] Methods to model centralized trading in a two-bus system described by Kirschen and Strbac (2004) were used to simulate the market-clearing price in the PJM East region, where the price hub of interest for PJM was located (see next section). The transmission constraint served to limit generators located in one region from supplying load in the other region. The general logic applied worked as follows:

(a) Calculate the unconstrained transmission flow by finding how much generation would need to flow from one region to the other to meet demand with a single market-clearing price.
(b) If the unconstrained transmission flow was less than the transmission capacity between the regions, then use the single price for both regions.
(c) If the unconstrained transmission flow was greater than the transmission capacity, then increase the effective demand in the low-cost region by 5,000 MW and decrease the effective demand in the high-cost region by 5,000 MW. Find the resulting prices in each region with the new effective demand.

Validation with Actual Prices

The annual average wholesale prices from the model were compared to actual annual average wholesale power energy prices in the RT market from major trading hubs in each region.

[51] Find transfer limit and flow data here: https://dataminer2.pjm.com/feed/transfer_limits_and_flows/definition.

Wholesale Electricity Price Hubs

Market	Years	Name
CAISO	2008-2017	SP15
ERCOT	2008-2017	North
SPP	2008-2012	OKGE
SPP	2017	South Hub
MISO	2008	Cinergy
MISO	2012-2017	Indiana Hub
PJM	2008-2017	Western Hub
NYISO	2008-2017	Hudson Valley Zone G
ISO-NE	2008-2017	Mass. Hub

One way to validate the modeled prices is to compare the price distribution curves of the modeled prices to the price distribution curves of the actual RT market prices at the hubs. These are shown for each region below, along with a comparison of the average modeled and actual RT prices.

Figure 29. Price duration curves for modeled and actual RT prices for CAISO.

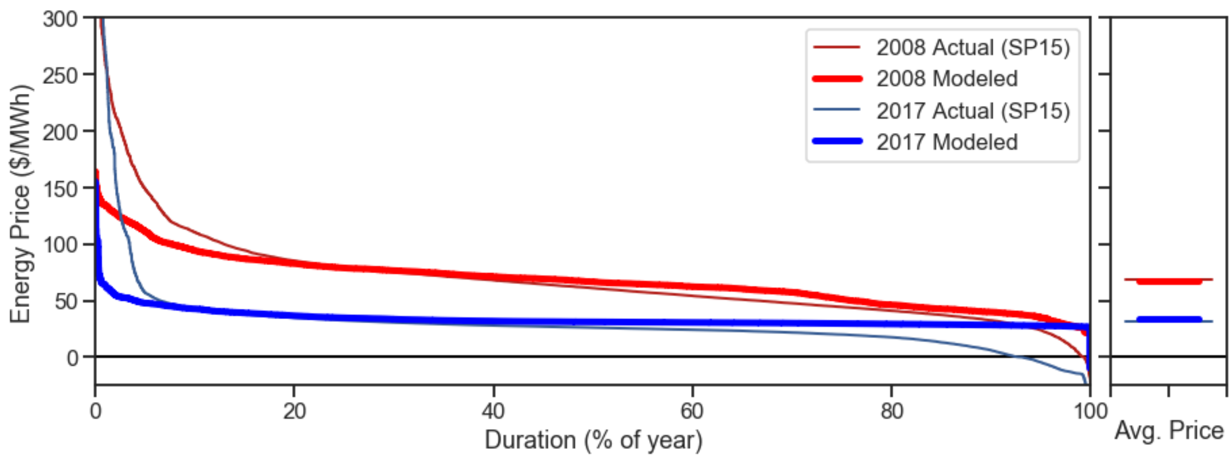


Figure 30. Price duration curves for modeled and actual RT prices for ERCOT.

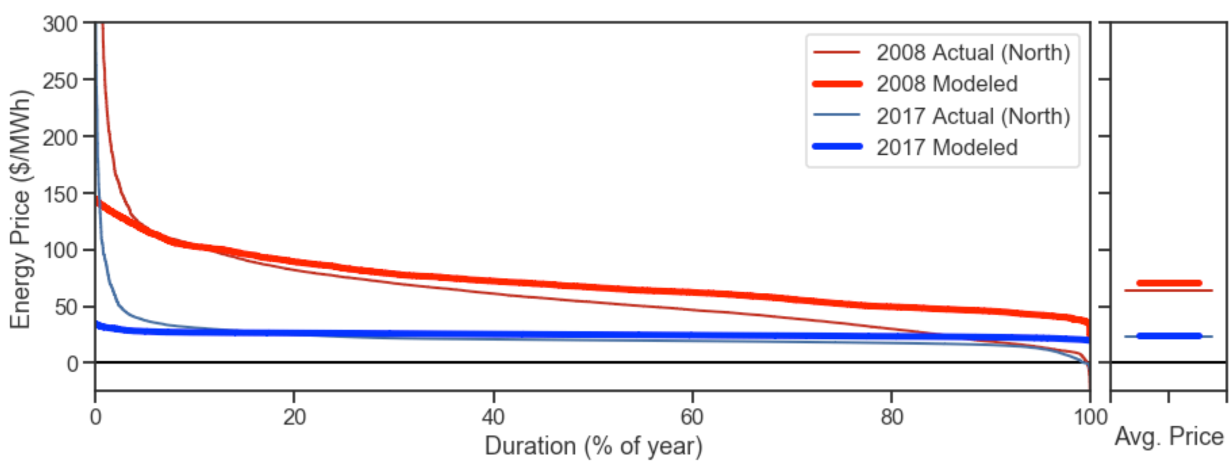


Figure 31. Price duration curves for modeled and actual RT prices for SPP.

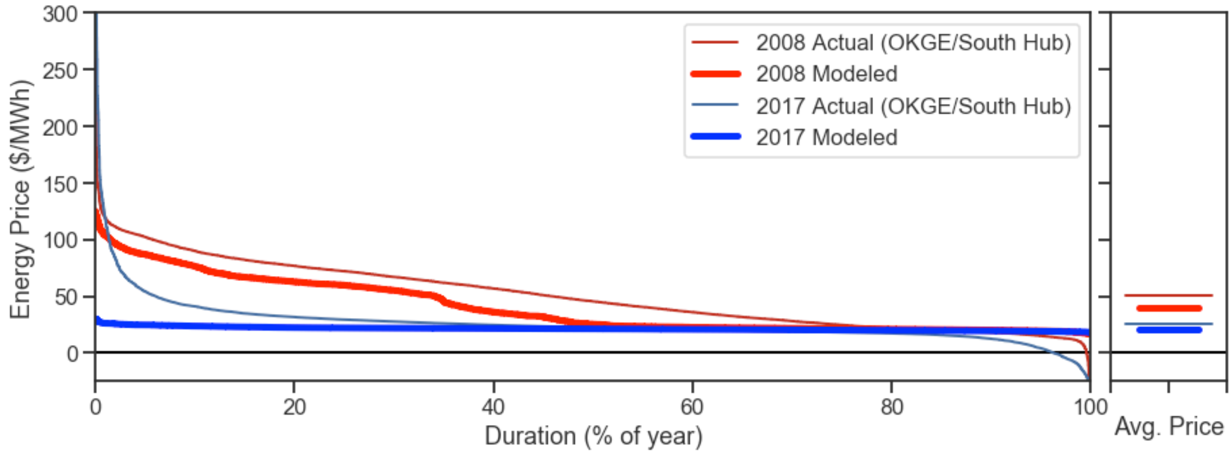


Figure 32. Price duration curves for modeled and actual RT prices for MISO.

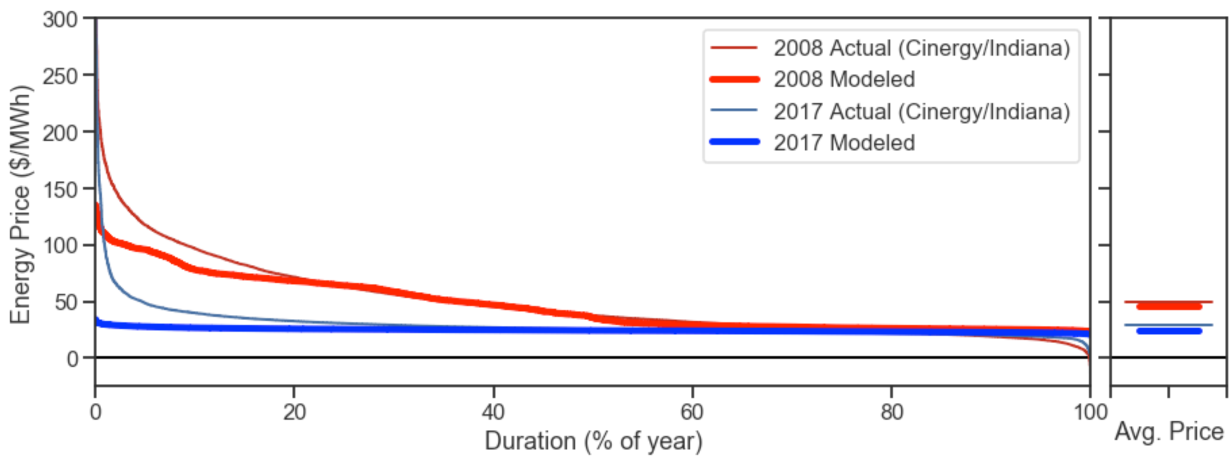


Figure 33. Price duration curves for modeled and actual RT prices for PJM.

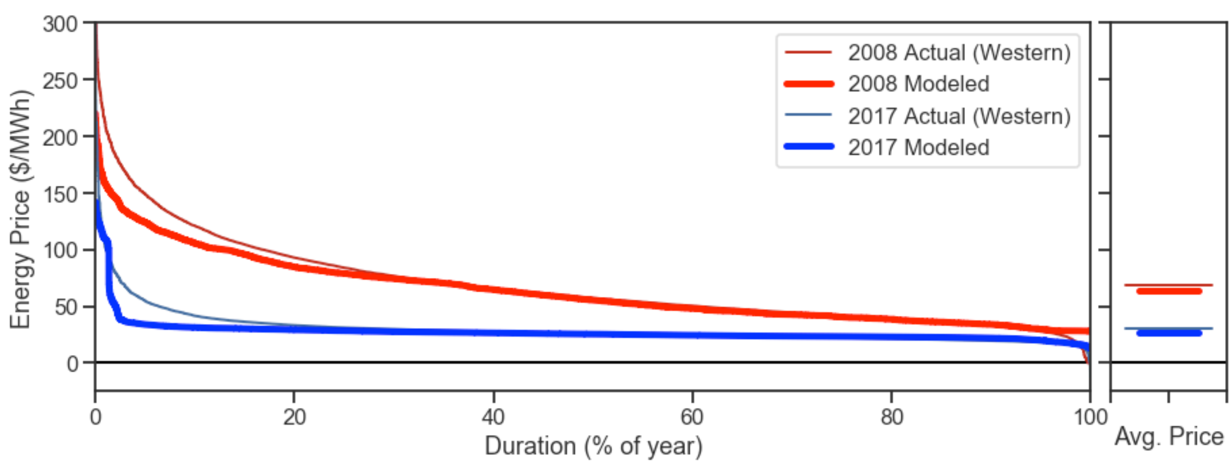


Figure 34. Price duration curves for modeled and actual RT prices for NYISO.

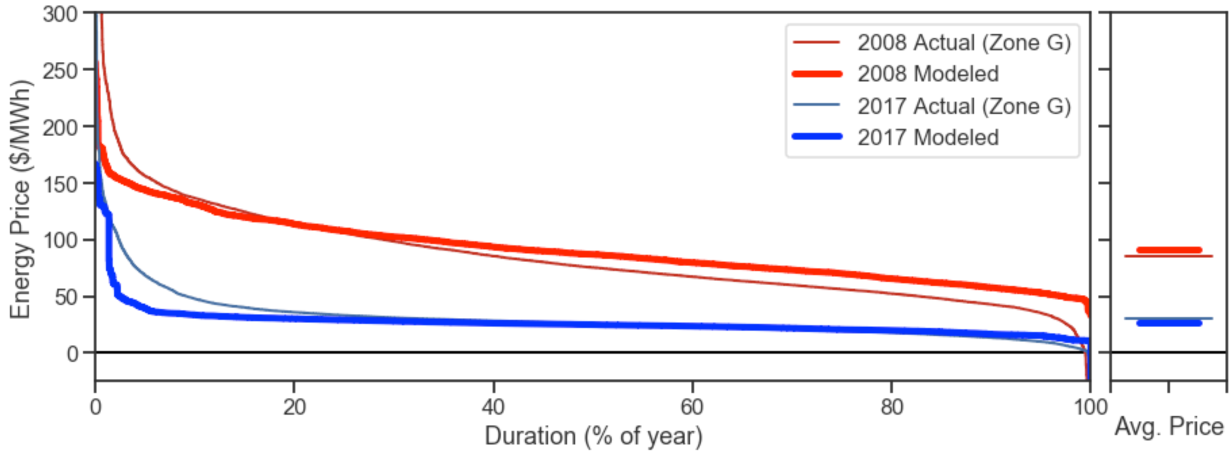
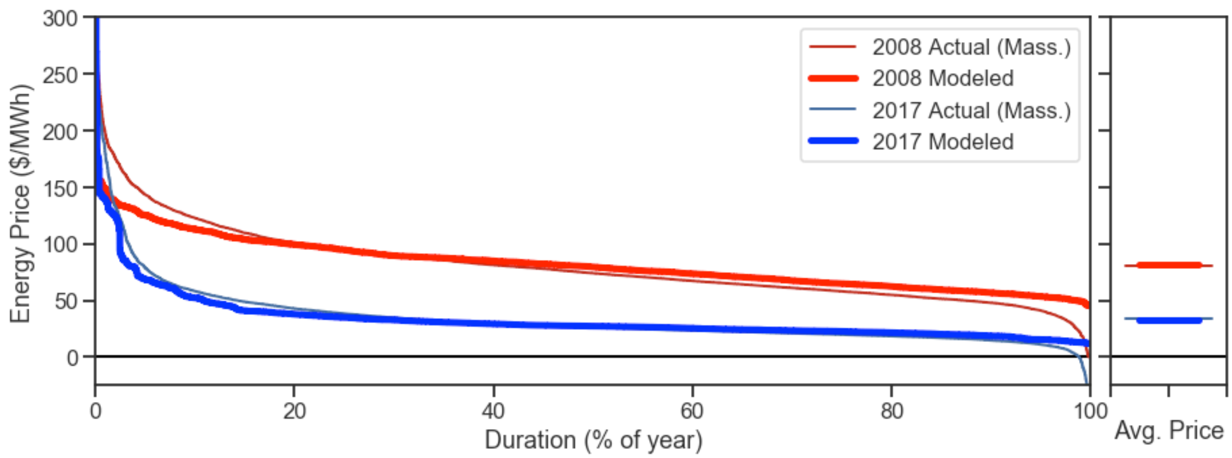


Figure 35. Price duration curves for modeled and actual RT prices for ISO-NE.



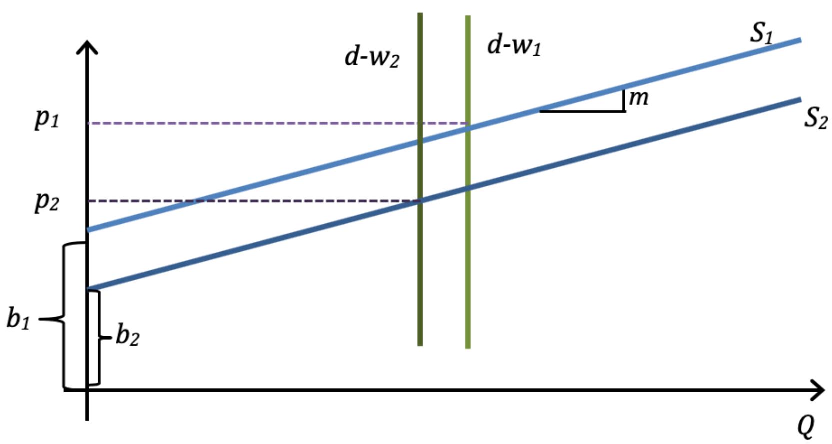
Appendix B: How Non-Linear Interactions Inhibit Quantification of Individual Factors' Contributions to Changes in Wholesale Prices

This appendix addresses the question of how non-linear interactions can prevent quantification of individual factors' contributions to changes in wholesale prices. First it illustrates that non-linear interactions do not occur when a supply curve is only shifted up or down. Then it shows how changes in the slope of the supply curve lead to non-linear interactions.

Consider a case where the supply curve (S) only shifts up and down, but the slope of the supply curve does not change with time (i.e., b_t can change over time, but m is fixed), illustrated by Figure 36. To further simplify, assume that demand (d) is fixed and only wind changes with time (w_t). The price (p) will be the intersection of the supply and demand curve, Eq. 1.

$$p(w_t, b_t) = (d - w_t)m + b_t \tag{1}$$

Figure 36. Supply curve with a fixed slope and changes in the offset with time.



Compare the price impact of changing one factor at a time (w_t and b_t) to the price impact of changing multiple factors at the same time to determine if there are any non-linear interactions. In the case of a supply curve that only shifts up or down, there is no non-linear interaction.

The price impact of changing wind from w_2 to w_1 (where $\Delta w = w_2 - w_1$) is:

$$\Delta p^w = p(w_2, b_2) - p(w_1, b_2) = -\Delta w \cdot m \tag{2}$$

The price impact of changing the supply curve by shifting the offset from b_2 to b_1 (where $\Delta b = b_2 - b_1$) is:

$$\Delta p^b = p(w_2, b_2) - p(w_2, b_1) = \Delta b \tag{3}$$

The price impact of changing both the offset of the supply curve and the wind at the same time is:

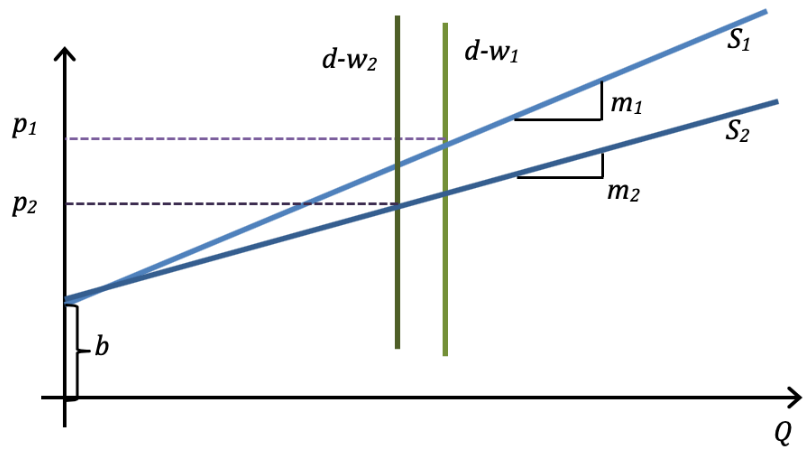
$$\Delta p^{w,b} = p(w_2, b_2) - p(w_1, b_1) = \Delta b - \Delta w \cdot m \tag{4}$$

The difference in the price impact from changing multiple factors at one time compared to the summation of the price impacts from changing the factors one at a time is a measure of the interaction. In the case where the supply curve is only shifted up or down, but the slope is not changed, there is no non-linear interaction. Hence, there is no difference in the price impact of changing factors simultaneously or summing the impact of changing factors individually:

$$Interaction = \Delta p^{w,b} - \left(\Delta p^{w} + \Delta p^{b}\right) = \Delta b - \Delta w \cdot m - (-\Delta w \cdot m + \Delta b) = 0 \tag{5}$$

Now consider a case where, instead of the supply curve shifting up or down, the slope of the supply curve increases or decreases (Figure 37).

Figure 37. Supply curve with a fixed offset and changing slope with time.



The price impact of changing wind from w_2 to w_1 (where $\Delta w = w_2 - w_1$) is:

$$\Delta p^{w} = p(w_2, m_2) - p(w_1, m_2) = -\Delta w \cdot m_2 \tag{6}$$

The price impact of changing the supply curve by changing the slope from m_2 to m_1 (where $\Delta m = m_2 - m_1$) is:

$$\Delta p^{m} = p(w_2, m_2) - p(w_2, m_1) = (d - w_2)\Delta m \tag{7}$$

The price impact of changing both the slope of the supply curve and the wind at the same time is:

$$\Delta p^{w,m} = p(w_2, m_2) - p(w_1, m_1) = d\Delta m - (w_2 m_2 {}_- w_1 m_1) \tag{8}$$

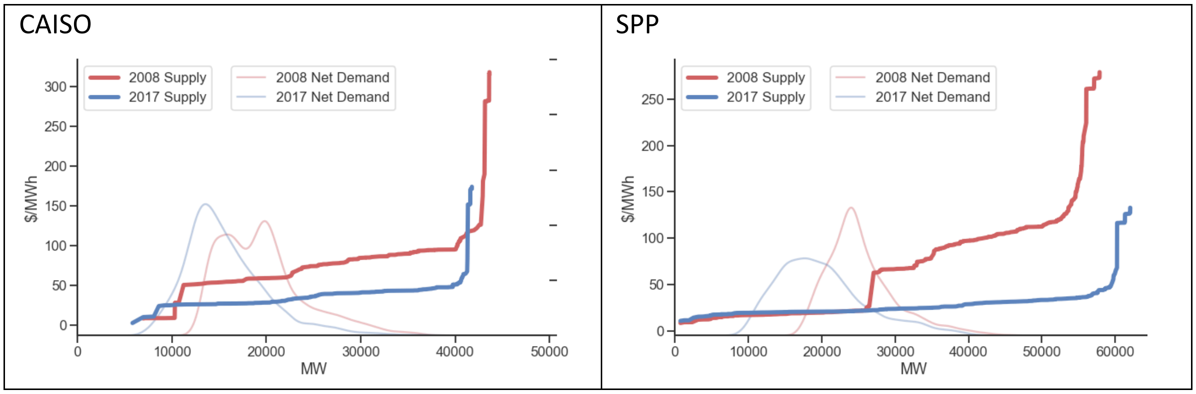
In the case where the slope of the supply curve changes, the non-linear interaction is non-zero. This non-linear interaction will lead to a difference between the effect of changing factors individually versus changing them simultaneously. For this case, the size of the interaction depends on the change in the slope and the change in wind:

$$Interaction = \Delta p^{w,m} - (\Delta p^{w} + \Delta p^{m}) = \Delta m \Delta w$$

(9)

The larger interaction term in SPP relative to CAISO can be explained in part by the more significant changes to the slope of the supply curve in SPP between 2008 and 2017. In contrast, higher gas prices in 2008 primarily shifted the supply curve up in CAISO (without significantly changing the slope) over the range of net demand levels in CAISO, as shown in Figure 38.

Figure 38. The supply curve for CAISO (left) shows little change in the slope between 2008 and 2017, whereas the slope more dramatically changed in SPP over the same period (right).



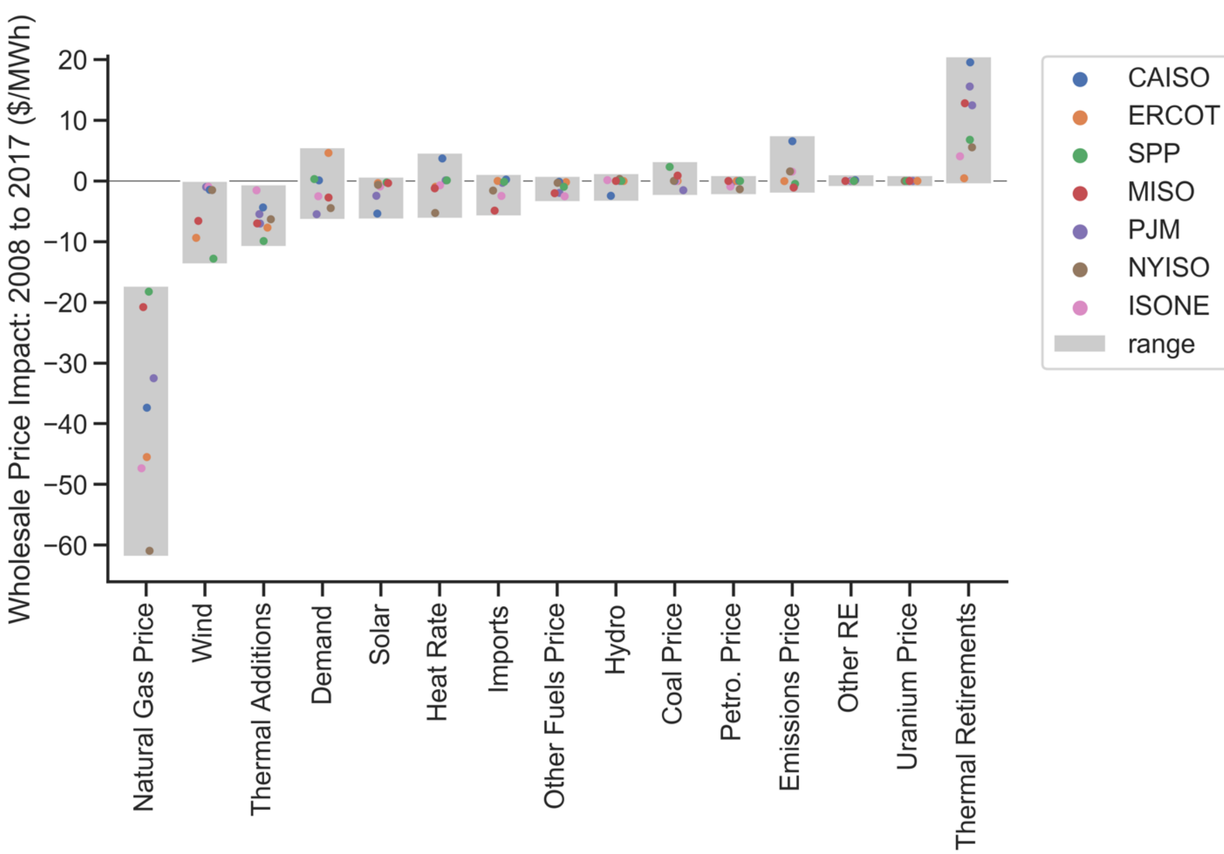
Appendix C: Wholesale Power Energy Price Impacts of Individual Factors with a 2008 Base Year

The primary analysis in the main text uses 2017 as a base year, meaning that all factors were kept constant at their 2017 levels, except one factor at a time was changed to its 2008 level. With 2017 as a base year, the non-linear interactions leads to an understatement of the overall change in prices between 2008 and 2017 due to the relatively flat supply curve in 2017.

Alternatively, 2008, a year with high natural gas prices and a relatively steep supply curve, can be the base year (Figure 39). With 2008 as the base year, changing individual factors to their 2017 levels tends to lead to overstated impacts. Natural gas remains by far the largest driver of changes in wholesale prices. The estimated impacts of wind and solar on average wholesale prices are much larger than found with 2017 as the base year, again due to the steeper supply curve in 2008 in comparison to 2017. The same is true for most other factors, given the steeper supply curve.

The use of 2017 as the base year is preferred, because it includes conditions that better reflect current reality.

Figure 39. Wholesale price impact of various factors that changed between 2008 and 2017 across all markets using a base year of 2008.



Appendix D: EIA Annual Energy Outlook and ABB Velocity Suite Projections for 2022

As discussed in Section 3.6, projections from both EIA's AEO 2018 and ABB's Velocity Suite database are used to model wholesale electricity price increases between 2017 and 2022 for all seven markets. This appendix presents the key assumptions used to model future-year generator additions/retirements, demand growth, and fuel price changes. ABB's Velocity Suite did not provide forecasts of demand growth, fuel price changes, and DPV increases to 2022. For that reason, these data inputs to the 2022 modeling stay the same between the EIA case (Section 3.6) and ABB case (Appendix E). Items in the tables below that do not have data projections from ABB's Velocity Suite are marked as "-". For the most part, the increase in wind and utility-scale solar in ABB's Velocity Suite is greater than EIA's AEO reference case, while the thermal generation additions and retirements are more similar to one another.

Table 2. EIA and ABB projections of generation additions by 2022.

Region	Category	AEO 2022 Additions (GW)	AEO % growth (2017-2022)	ABB % growth (2017-2022)
ERCOT	Coal	0.0	0%	0%
ERCOT	Oil and Natural Gas Steam	0.0	0%	0%
ERCOT	Combined Cycle	3.2	9%	23%
ERCOT	Combustion Turbine/Diesel	9.6	150%	37%
ERCOT	Nuclear	0.0	0%	0%
MISO	Coal	0.0	0%	0%
MISO	Oil and Natural Gas Steam	0.0	0%	1%
MISO	Combined Cycle	3.9	19%	15%
MISO	Combustion Turbine/Diesel	1.3	7%	3%
MISO	Nuclear	0.0	0%	0%
SPP	Coal	0.0	0%	0%
SPP	Oil and Natural Gas Steam	0.0	0%	0%
SPP	Combined Cycle	0.0	0%	0%
SPP	Combustion Turbine/Diesel	0.6	6%	1%
SPP	Nuclear	0.0	0%	0%
NYISO	Coal	0.0	0%	0%

NYISO	Oil and Natural Gas Steam	0.0	0%	0%
NYISO	Combined Cycle	1.7	19%	37%
NYISO	Combustion Turbine/Diesel	0.5	9%	3%
NYISO	Nuclear	0.0	0%	0%
ISO-NE	Coal	0.0	0%	0%
ISO-NE	Oil and Natural Gas Steam	0.0	0%	0%
ISO-NE	Combined Cycle	0.7	6%	19%
ISO-NE	Combustion Turbine/Diesel	0.6	22%	7%
ISO-NE	Nuclear	0.0	0%	0%
CAISO	Coal	0.0	0%	0%
CAISO	Oil and Natural Gas Steam	0.0	0%	0%
CAISO	Combined Cycle	1.1	6%	12%
CAISO	Combustion Turbine/Diesel	0.7	6%	8%
CAISO	Nuclear	0.0	0%	0%
PJM East	Coal	0.0	0%	0%
PJM East	Oil and Natural Gas Steam	0.2	3%	1%
PJM East	Combined Cycle	6.4	33%	71%
PJM East	Combustion Turbine/Diesel	0.4	6%	2%
PJM East	Nuclear	0.0	0%	4%
PJM West	Coal	0.0	0%	0%
PJM West	Oil and Natural Gas Steam	0.1	5%	1%
PJM West	Combined Cycle	4.2	31%	71%
PJM West	Combustion Turbine/Diesel	0.1	0%	2%
PJM West	Nuclear	0.0	0%	4%

Table 3. EIA and ABB projections of generator retirements by 2022.

Region	Category	AEO 2022 Retirements (GW)	AEO % reduction (2017-2022)	ABB % reduction (2017-2022)

ERCOT	Coal	7.3	37%	34%
ERCOT	Oil and Natural Gas Steam	1.0	8%	4%
ERCOT	Combined Cycle	0.1	0%	0%
ERCOT	Combustion Turbine/Diesel	0.0	0%	1%
ERCOT	Nuclear	0.0	0%	0%
MISO	Coal	1.8	5%	15%
MISO	Oil and Natural Gas Steam	1.7	11%	18%
MISO	Combined Cycle	0.3	2%	0%
MISO	Combustion Turbine/Diesel	1.0	5%	9%
MISO	Nuclear	0.8	8%	10%
SPP	Coal	2.2	12%	5%
SPP	Oil and Natural Gas Steam	2.7	23%	13%
SPP	Combined Cycle	0.6	5%	0%
SPP	Combustion Turbine/Diesel	0.7	7%	9%
SPP	Nuclear	0.0	0%	0%
NYISO	Coal	0.2	9%	24%
NYISO	Oil and Natural Gas Steam	0.0	0%	10%
NYISO	Combined Cycle	0.1	1%	0%
NYISO	Combustion Turbine/Diesel	0.1	2%	44%
NYISO	Nuclear	2.1	38%	40%
ISO-NE	Coal	0.2	22%	49%
ISO-NE	Oil and Natural Gas Steam	0.2	4%	4%
ISO-NE	Combined Cycle	1.2	10%	0%
ISO-NE	Combustion Turbine/Diesel	0.0	0%	24%
ISO-NE	Nuclear	0.7	17%	15%
CAISO	Coal	0.0	0%	0%
CAISO	Oil and Natural Gas Steam	5.4	49%	114%
CAISO	Combined Cycle	1.3	7%	0%
CAISO	Combustion Turbine/Diesel	2.2	21%	5%
CAISO	Nuclear	0.0	0%	0%
PJM East	Coal	1.3	10%	21%

PJM East	Oil and Natural Gas Steam	1.8	28%	19%
PJM East	Combined Cycle	0.7	4%	1%
PJM East	Combustion Turbine/Diesel	0.5	6%	10%
PJM East	Nuclear	1.4	10%	16%
PJM West	Coal	7.5	13%	21%
PJM West	Oil and Natural Gas Steam	1.3	64%	19%
PJM West	Combined Cycle	0.0	0%	1%
PJM West	Combustion Turbine/Diesel	0.3	2%	10%
PJM West	Nuclear	2.1	12%	16%

Table 4. EIA projections of fuel cost increases to 2022.

Region	Category	AEO 2022 Price ($/MMBtu)	AEO % increase (2017-2022)	ABB % increase (2017-2022)
ERCOT	Coal	2.6	21%	-
ERCOT	Natural Gas	4.3	38%	-
ERCOT	Distillate Fuel Oil	21.7	57%	-
ERCOT	Residual Fuel Oil	15.0	67%	-
MISO	Coal	2.4	23%	-
MISO	Natural Gas	4.6	36%	-
MISO	Distillate Fuel Oil	20.8	48%	-
MISO	Residual Fuel Oil	11.2	88%	-
SPP	Coal	2.4	24%	-
SPP	Natural Gas	4.6	40%	-
SPP	Distillate Fuel Oil	21.1	50%	-
SPP	Residual Fuel Oil	12.5	84%	-
NYISO	Coal	15.2	13%	-
NYISO	Natural Gas	4.5	38%	-
NYISO	Distillate Fuel	25.4	80%	-

	Oil			
NYISO	Residual Fuel Oil	15.3	58%	-
ISO-NE	Coal	21.3	676%	-
ISO-NE	Natural Gas	5.1	23%	-
ISO-NE	Distillate Fuel Oil	22.1	58%	-
ISO-NE	Residual Fuel Oil	15.1	31%	-
CAISO	Coal	2.2	12%	-
CAISO	Natural Gas	4.7	31%	-
CAISO	Distillate Fuel Oil	24.6	75%	-
CAISO	Residual Fuel Oil	19.8	49%	-
PJM East	Coal	2.9	14%	-
PJM East	Natural Gas	4.5	38%	-
PJM East	Distillate Fuel Oil	25.0	78%	-
PJM East	Residual Fuel Oil	14.1	35%	-
PJM West	Coal	2.6	17%	-
PJM West	Natural Gas	4.3	36%	-
PJM West	Distillate Fuel Oil	21.7	54%	-
PJM West	Residual Fuel Oil	14.3	71%	-

Table 5. EIA projections of demand changes to 2022.

Region	Category	AEO 2022 Demand (TWh/yr)	AEO % increase (2017-2022)	ABB % increase (2017-2022)
ERCOT	Total Net Energy for Load	383.4	9%	-
MISO	Total Net Energy for Load	522.7	5%	-
SPP	Total Net Energy for Load	227.3	7%	-
NYISO	Total Net Energy for	154.8	2%	-

	Load			
ISO-NE	Total Net Energy for Load	115.7	-4%	-
CAISO	Total Net Energy for Load	281.2	2%	-
PJM East	Total Net Energy for Load	274.1	2%	-
PJM West	Total Net Energy for Load	518.0	3%	-

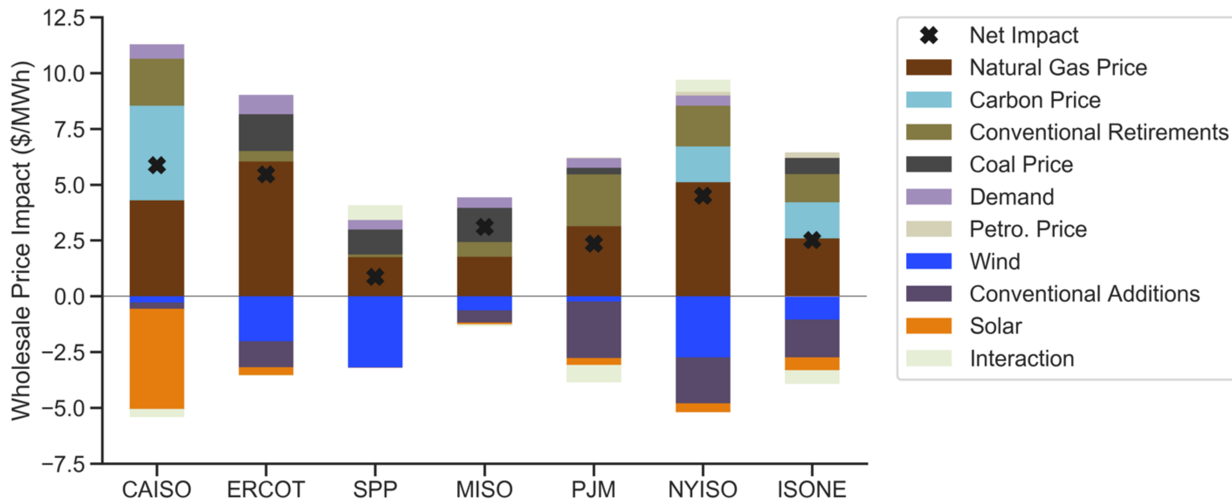
Table 6. EIA and ABB projections of wind and solar growth to 2022.

Region	Category	AEO 2022 Generation (TWh/yr)	AEO % increase (2017-2022)	ABB % increase (2017-2022)
ERCOT	UPV	5.0	218%	739%
ERCOT	DPV	1.3	156%	-
ERCOT	Wind	58.3	28%	78%
MISO	UPV	3.5	355%	368%
MISO	DPV	1.4	163%	-
MISO	Wind	90.6	58%	93%
SPP	UPV	0.6	10%	156%
SPP	DPV	1.0	157%	-
SPP	Wind	98.8	66%	102%
NYISO	UPV	0.8	334%	1605%
NYISO	DPV	3.4	89%	-
NYISO	Wind	5.7	45%	272%
ISO-NE	UPV	0.9	7%	109%
ISO-NE	DPV	7.7	173%	-
ISO-NE	Wind	3.8	10%	191%
CAISO	UPV	42.2	104%	68%
CAISO	DPV	17.9	99%	-
CAISO	Wind	26.7	103%	51%
PJM East	UPV	1.4	11%	228%
PJM East	DPV	4.1	93%	-
PJM East	Wind	3.5	17%	119%
PJM West	UPV	0.5	12%	228%
PJM West	DPV	1.5	103%	-
PJM West	Wind	22.1	31%	119%

Appendix E: Outlook to 2022 Based on ABB Velocity Suite

An alternative to EIA's reference case is to use the planned generation additions and retirements from ABB's Velocity Suite. This alternative results in greater VRE in all markets compared with EIA's reference case except for CAISO, where EIA projects greater wind and solar. Overall the conclusions based on using the EIA projections are not dramatically different. ABB's Velocity Suite case leads to less price impacts from solar in CAISO and greater impacts of wind particularly in SPP, NYISO, and ERCOT.

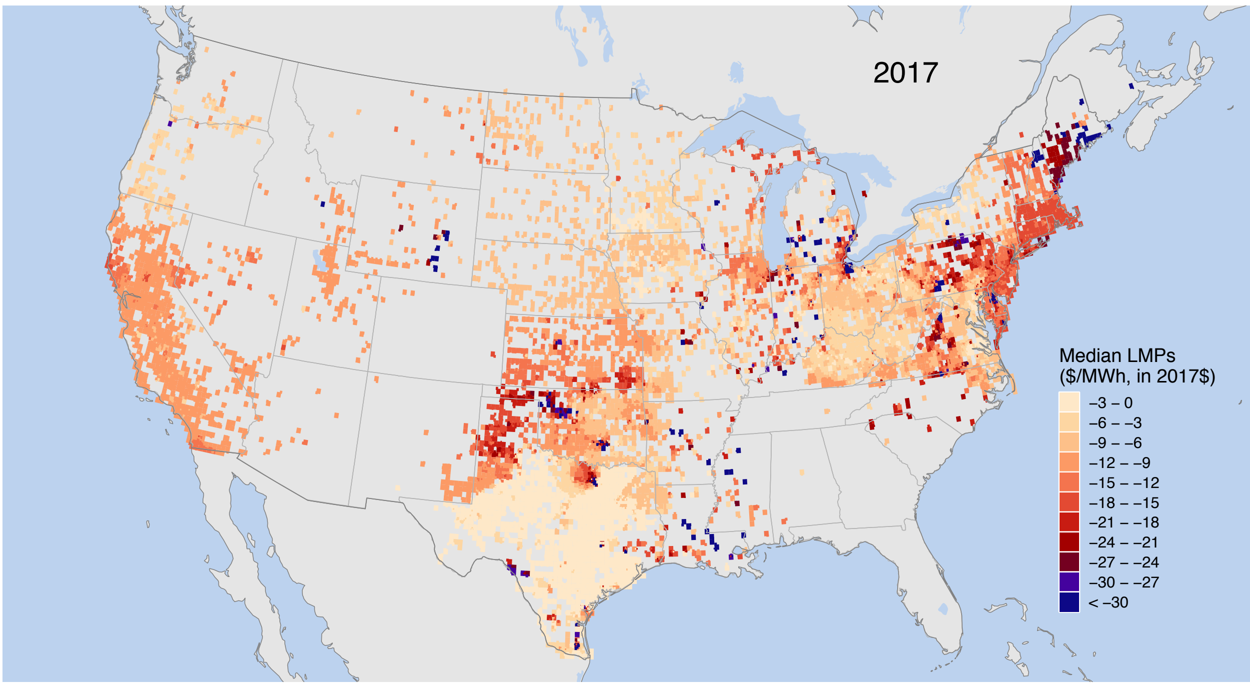
Figure 40. Average wholesale power energy price impact of various factors that are expected to change between 2017 and 2022 across all markets using ABB Velocity Suite data rather than EIA.



Appendix F: Median of Negative Prices

Both the frequency and magnitude of negative prices drive the overall impact of negative prices on the average price at various nodes. The magnitude of negative prices, as measured by the median negative price in 2017, is larger in some regions than in others. Areas in the Northeast, for example, have much larger negative prices than do the ERCOT portions of Texas.

Figure 41. Median of negative LMPs at each node in 2017.



LMP = locational marginal price

Appendix G: Generation Patterns During Positive- and Negative-Price Hours in Other ISOs/RTOs

Examination of generation data when the energy component of the LMP was negative (vs. positive) illustrates that wind generated more when prices were negative, though for MISO, ISO-NE, and NYISO wind was a relatively small fraction of the generation during these times. In ERCOT and SPP, in contrast, wind was a large faction of the overall generation during times when the energy component of the LMP was negative. For MISO, the energy component of the LMP was never negative in 2017, hence results for 2016 are shown instead. For ISO-NE, NYISO, and ERCOT, this focus is on 2017, though the patterns in 2016 were similar. For completeness, the generation as a percentage of peak output is also shown for CAISO.

Figure 42. Generation during times when the energy component of the LMP was positive or negative in MISO for 2016.

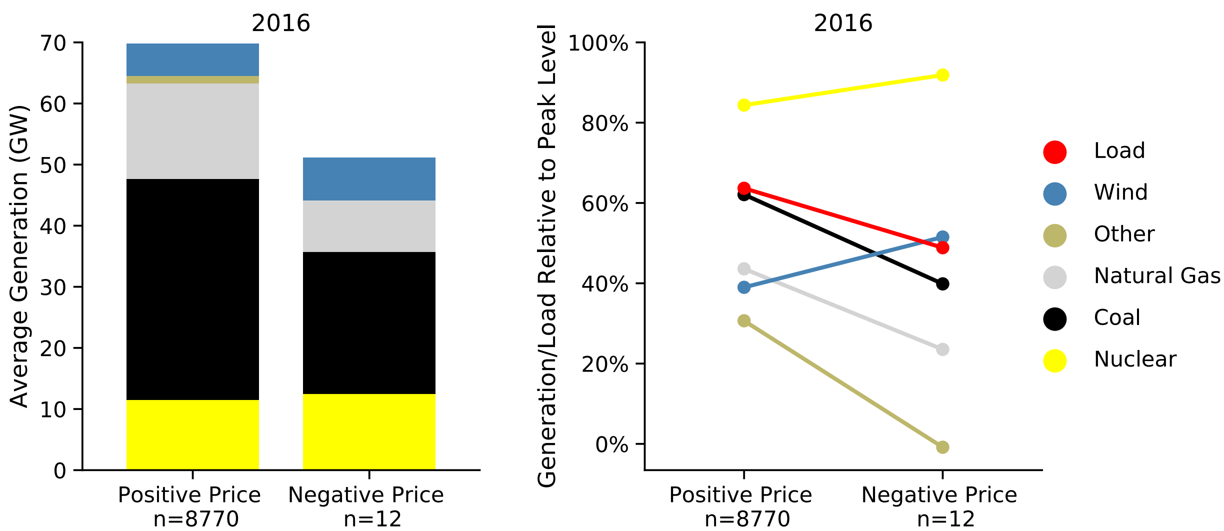


Figure 43. Generation during times when the energy component of the LMP was positive or negative in NYISO for 2017.

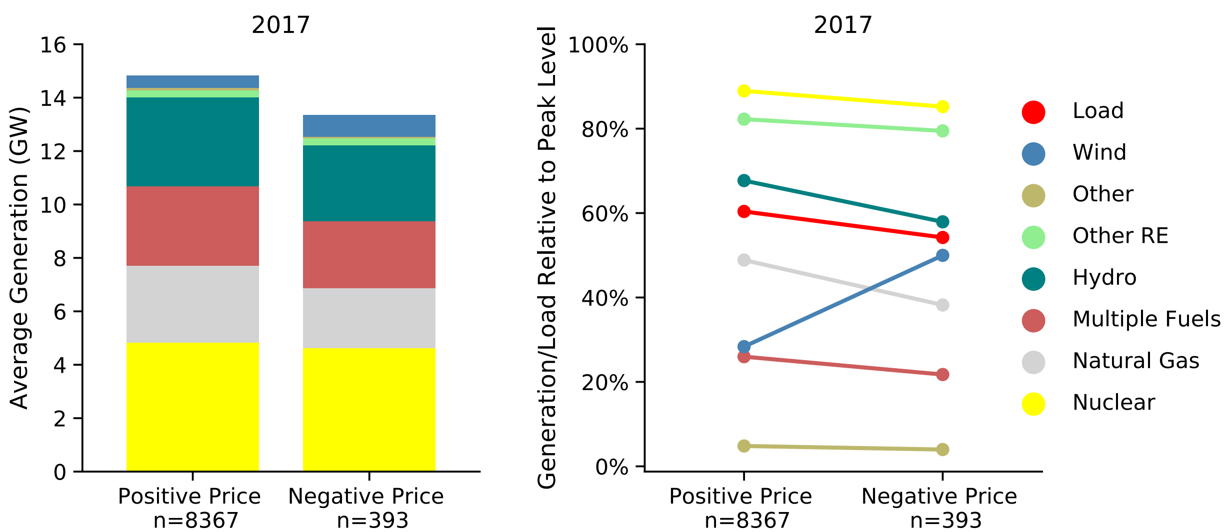


Figure 44. Generation during times when the energy component of the LMP was positive or negative in ERCOT for 2017.

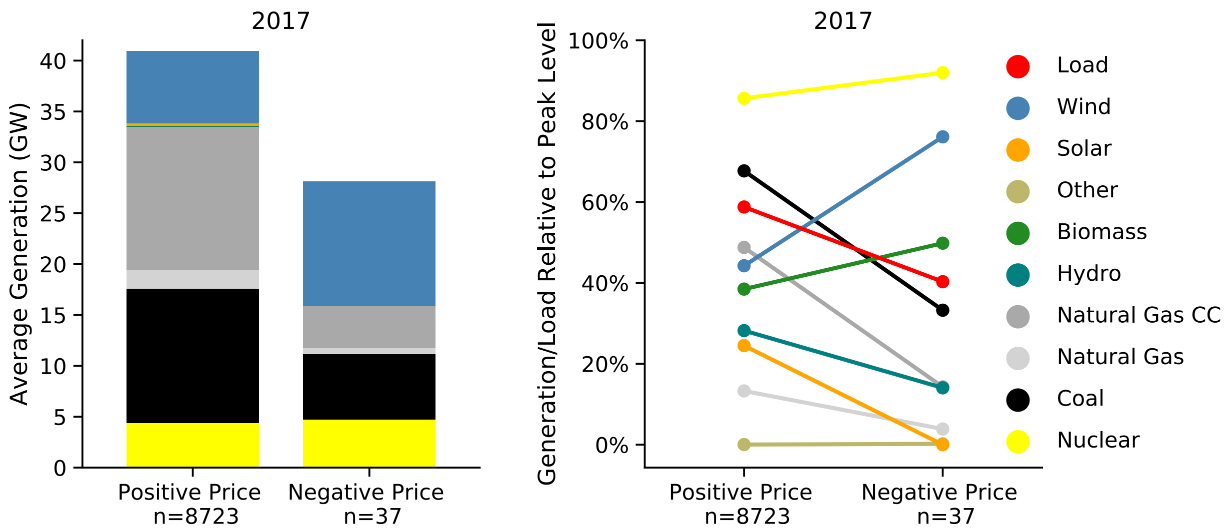


Figure 45. Generation during times when the energy component of the LMP was positive or negative in ISO-NE for 2017.

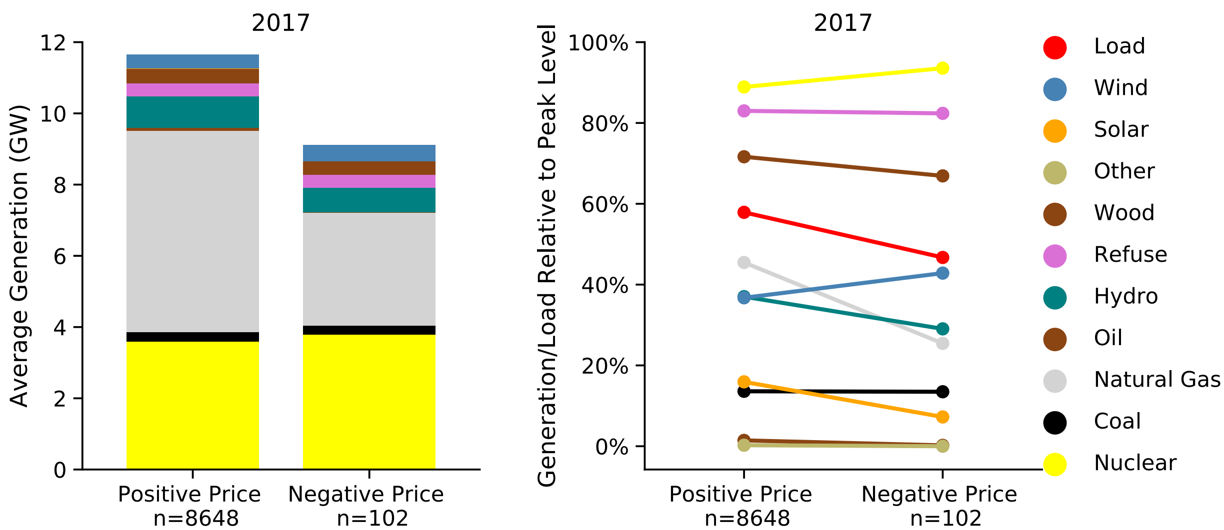


Figure 46. Generation during times when the energy component of the LMP was positive or negative in PJM for 2017.

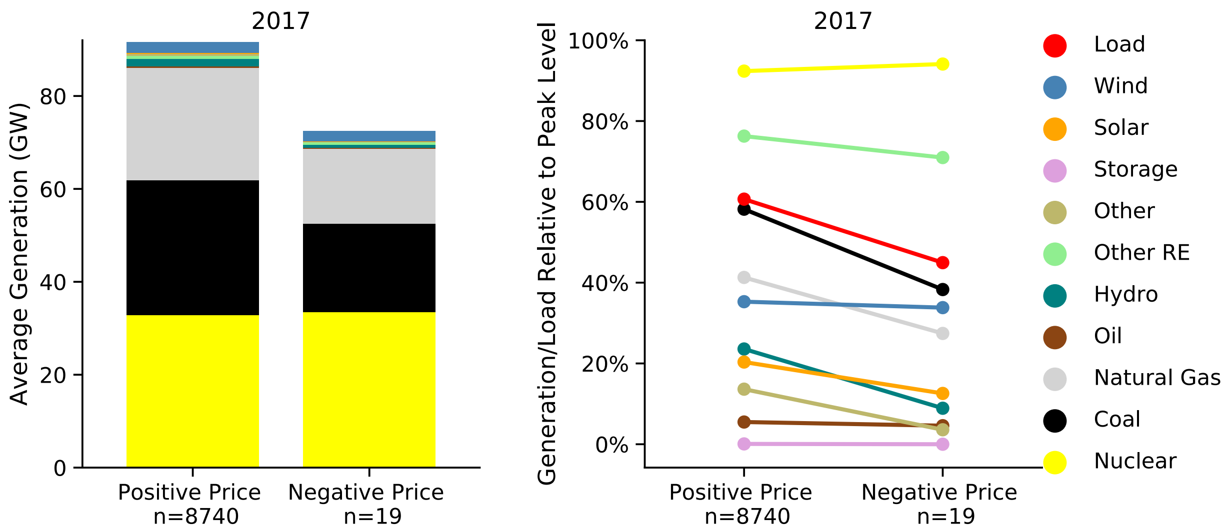


Figure 47. Generation during times when the energy component of the LMP was positive or negative in CAISO for 2017.